this section), new small boiler exemption affidavits as described in paragraph (b)(3) of this section will be available to natural gas suppliers for purposes of paragraph (b)(2) of this section and to any other interested person upon request from the Office of Public Information, Federal Energy Regulatory Commission, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

(2) *Availability of exemption affidavits from natural gas suppliers.* (i) Natural gas suppliers shall notify facilities which may be eligible for an exemption under § 282.210 and shall mail a new small boiler exemption affidavit to those facilities which request one.

(ii) Natural gas suppliers shall make new small boiler exemption affidavits available at their principal place of business on an ongoing basis during regular business hours.

(3) *Contents of exemption affidavit.* The new small boiler exemption affidavit will provide the owner or operator of an industrial boiler fuel facility with an opportunity to respond to the following question: Did your facility come into existence after November 9, 1978, and does the facility, on the basis of records, documents, or data in the customer's posssesion, have a total capacity which is no more than 300 Mcf per day?

Appendix A

Note.—This appendix will not appear in the Code of Federal Regulations.

Federal Energy Regulatory Commission, Washington, D.C.

Exemption From Incremental Pricing for the Use of Natural Gas in New Small Boiler Fuel Facilities

Docket No. RM79-48

Participation is Voluntary. Copies of executed exemption affidavits filed with the Commission shall be available through the Office of Public Information, Room 1000, 825 North Capitol Street, NE., Washington, D.C. 20426.

Please Read Before Completing This Affidavit

Purpose

The Natural Gas Policy Act of 1978 (NGPA) provides that natural gas used as boiler fuel by any industrial boiler fuel facility will be subject to incremental pricing surcharges unless exempted. The statute provides for certain exemptions from these incremental pricing surcharges. The affidavit entitled "Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas" serves the purpose of identifying those uses of natural gas that are entitled to a full or partial statutory exemption.

In addition, the statute provides that the Federal Energy Regulatory Commission has the discretion to propose other exemptions from the incremental pricing program. The Commission has issued a rule which provides that new small industrial boiler fuel facilities which have come into existence since November 9, 1978, are eligible for an exemption from incremental pricing. This affidavit serves the purpose of identifying those "new" small boiler facilities which are entitled to an exemption from incremental pricing surcharges.

Notice

If you do not complete and return this affidavit or the affidavit entitled "Exemptions From Incremental Pricing for Certain Categories of Industrial Boiler Fuel Use of Natural Gas," setting forth your claim to an exemption *ALL* gas sold to your facility will be subject to incremental pricing surcharges. Additionally, if circumstances or ownership change, you should immediately notify your natural gas supplier(s) of the change so that the correct amount of surcharge may be calculated as to your gas use or, if needed, you may complete a new exemption affidavit to obtain a new or changed exemption from the incremental pricing surcharges. Failure to report changes can subject your facility to civil penalties of appropriate amounts under Section 504 of the Natural Gas Policy Act of 1978.

General Instructions

If you claim an exemption from incremental pricing surcharges for the gas used by your facility which has been identified by your natural gas supplier as a potentially non-exempt industrial boiler fuel facility, this affidavit should be completed and signed, under oath, by a responsible official associated with the facility. A separate affidavit must be filed for each facility for which an exemption from incremental pricing surcharges is claimed.

The original and five copies of this affidavit should be submitted to: Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, D.C. 20426.

Also, one copy must be submitted to your natural gas supplier. Additionally, each industrial facility shall retain such records, documents and data which formed the basis for the exemption claimed on this affidavit. Definitions which may be helpful in completing this affidavit are provided below.

If you have any questions concerning this affidavit, contact Ms. Alice Fernandez on (202) 275-4406.

Definitions

(1) "Natural gas supplier" means an interstate pipeline or a local distribution company.

(2) "Local distribution company" means any person other than an interstate pipeline that receives gas directly or indirectly from an interstate pipeline and which is engaged in sale of natural gas for resale or for ultimate consumption. A person is not considered as having received gas directly or indirectly from an interstate pipeline if the only service performed by an interstate pipeline for the purchaser is a transportation service.

(3) "Boiler fuel use" means the use of any fuel for the generation of steam or electricity.

(4) "Facility" means all buildings and equipment located at the same geographic site which are commonly considered to be part of one plant, mill, refinery, or other industrial complex.

(5) "Industrial facility" means any facility engaged primarily in the extraction or processing of raw materials, or in the processing or changing of raw or unfinished materials into another form or product.

(6) "Non-exempt industrial boiler fuel facility" means any industrial boiler fuel facility other than any such facility which has been exempted from the incremental pricing program in accordance with Part 282 of the Commission's rules and regulations.

(7) "Capacity" means, as to a boiler which has the capability to burn natural gas, the volume of natural gas, stated in Mcf, which would be consumed if the boiler were operated at nameplate rated capacity for a continuous 16 hour period. The capacity of a boiler whose nameplate rated capacity is stated in terms of MMBtu per hour shall be obtained by converting the MMBtu rating to an Mcf equivalent. This conversion shall be based on a conversion factor of one MMBtu to one Mcf.

(8) "Total capacity of a facility" is the sum of the capacities of all boilers within an industrial boiler fuel facility which have the capability to burn natural gas.

1.0 Name of Company or Organization: ——

* * * * *

2.0 Name of Facility: ——

* * * * *

3.0 Address: Number —— Street ——

City/Town County State Zip Code

* * * * *

4.0 Name of Natural Gas Supplier: ——

5.0 Did your facility come into existence after November 9, 1978, and does your facility, on the basis of records, documents or data in your possession, have a total capacity, as defined in the "Definitions" of this affidavit, which is no more than 300 Mcf per day?

(a) ☐ Yes . . . Sign and return affidavit

(b) ☐ No . . . Do not return affidavit

Dated: ——

Person completing this affidavit:

Name ——

Title ——

Phone Number ——

Subscribed and sworn to before me this —— day of ——

Notary Public——.

[FR Doc. 79-30759 Filed 10-3-79; 8:45 am]

BILLING CODE 6450-01-M

18 CFR Part 282

[Docket No. RM79-45]

Exemption from Incremental Pricing for Load-Balancing Facilities Which Burn Coal; Intent not to Establish a Rulemaking Proceeding

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Intent not to Establish a Rulemaking Proceeding.

SUMMARY: In the Notcie of Proposed Rulemaking issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (June 5, 1979 (44 FR 33099, June 8, 1979)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with respect to an exemption from incremental pricing for load-balancing facilities which have the capability to burn coal. Based upon a review of the comments, the Commission has determined not to institute a rulemaking proceeding in this matter. Thus, the Commission hereby gives notice that Docket No. RM79-45 is terminated.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, (202) 357-8033.

Issued: September 28, 1979.

I. Background

In the Notice of Proposed Rulemaking issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (June 5, 1979 (44 FR 33099, June 8, 1979)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with the respect to an exemption from incremental pricing for load-balancing facilities which have the capability to burn coal. Such an exemption was discussed at pp. 11-16 of the June 5th Notice (pp. 33100-33101 in the **Federal Register**).

On July 3, 1979 a Notice of Opportunity to Comment on Whether a Rulemaking Proceeding Should be Established (44 FR 40898, July 13, 1979) was issued for the purpose of providing further public notice of the announcement which was included in the Docket No. RM79-14 Notice of Proposed Rulemaking. Comments were due no later than August 1, 1979.

Fourteen comments were received in this docket. A list of those commenting is attached to this notice as an Appendix. Based upon a review of these comments and its own analysis, the Commission has determined not to institute a rulemaking proceeding in this matter. Thus, the Commission hereby gives notice that no rulemaking proceeding will be established and Docket No. RM79-45 is terminated.

II. Discussion

Nine of the fourteen comments received in this docket requested the institution of a rulemaking proceeding to exempt from the incremental pricing program all load-balancing facilities which have the capability to burn coal. Five of these comments expressed concern that, if load-balancing facilities which have the capability to burn coal are subject to incremental pricing, there will be a potential for those facilities to shift from the use of gas to the use of coal.

The commenters argued that raising the price of gas to a price, at a minimum, proximate to the price of No. 6 fuel oil would make it economically impractical for load-balancing facilities to continue to burn gas because the price of coal is already much lower than the price of No. 6 fuel oil. If substantial switching were to occur, the result could be higher prices to high priority customers because there would be fewer industrial users to share the fixed costs of operating a pipeline system. The counter-balancing argument to this point is, of course, that an exemption for load-balancing facilities which have the capability to burn coal would quite probably result in higher prices to high priority customers because the costs which could not be passed through by way of incremental pricing surcharges would then be passed on to high priority users.

It has not been established that a substantial amount of load-shifting will occur if facilities with coal-burning capability are subject to incremental pricing. Although the commenters were concerned about the potential for load-shifting, none of the comments attempted to estimate either the number of facilities that may be expected to switch to coal for use as a boiler fuel or the amount of gas sales that would be lost if these load-balancing facilities were not exempt from incremental pricing.

In addition, the characteristics and effects of load-balancing on rate structures vary from system to system. The American Gas Association emphasized that load-balancing is not a concept susceptible to uniform national treatment. It is possible that the benefits of some load-balancing sales may diminish for certain distribution companies if there is no exemption from incremental pricing for such sales. That possiblity, however, does not justify a blanket exemption for all load-balancing facilities which have the capability to burn coal.

The Commission's primary reason for not granting a blanket exemption for load-balancing facilities which have the capability to burn coal is that such an exemption would be contrary to national energy policy. The effect of a blanket exemption for facilities which have the capability to burn coal would be to encourage the consumption of gas instead of coal. Recent legislation such as the Powerplant and Industrial Fuel Use Act reflects the national energy policy to encourage the consumption of coal, which is our most abundant energy resource, in those facilities where coal can be utilized. The Commission believes that is should not take any action which would be inconsistent with or weaken this policy.

Congress has given the Commission, in sections 206(d) and 502(c) of the NGPA, the flexibility to provide relief when necessary. The Commission believes that the regulations which implement these two provisions, 18 CFR 282.206 and 18 CFR 1.41, provide adequate avenues for any party to request administrative relief on a case-by-case basis. An adjustment under § 1.41 in the form of an exception to the incremental pricing regulations in Part 282 may be granted upon a showing by the applicant that relief is necessary to prevent special hardship, inequity or an unfair distribution of burdens. The Commission has the capability to rapidly process a § 1.41 petition for relief and believes it will be able to handle any such petitions in an expeditious and equitable manner.

However, the Commission does not intend that the § 1.41 procedures should provide the vehicle for generalized challenges to Title II of the NGPA and the regulations promulgated thereunder. The § 1.41 procedures have been adopted by the Commission simply to provide an avenue of administrative relief for parties which are uniquely affected by Commission regulations, and not to provide an arena for inquiries into policy questions of broad applicability.

The four comments which opposed the establishment of a rulemaking proceeding in this docket stated reasons generally consistent with those described above for not proceeding any further with a rulemaking to exempt load-balancing facilities which have the capability to burn coal. One comment argued that the Commission should go one step further and encourage conversions to coal in order to free gas supplies for use in boilers where coal is not a feasible alternative.

For the reasons stated in this notice, a rulemaking regarding an exemption from incremental pricing for load-balancing facilities which have the capability to burn coal will not be initiated The Commission hereby gives notice that Docket No. RM79-45 is terminated.

By direction of the Commission.

Lois D. Cashell,

Acting Secretary.

Appendix

Following is a list of those who submitted comments in Docket No. RM79-45:

The American Gas Association
Associated Gas Distributors
The Kennecott Copper Corporation, et al
Mountain Fuel Supply Company
Natural Gas Pipeline Company of Ameria
Potlatch Corporation
The Process Gas Consumers Group, The Georgia Industrial Gas Group, and The American Iron and Steel Institute
Public Service Company of Colorado
Public Service Electric and Gas Company
Republic Steel Corporation
Richard Smyth, Commissioner, Wyoming Public Utilities Commission
State of Wisconsin, Public Service Commission
The United Distribution Companies
Wisconsin Gas Company

[FR Doc. 79-30780 Filed 10-3-79; 8:45 am]
BILLING CODE 6450-01-M

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18 CFR Part 282

[Docket No. RM79-46]

Exemption From Incremental Pricing for Load-Balancing Facilities Which Burn Oil; Intent Not to Establish a Rulemaking Proceeding

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Intent not to Establish a Rulemaking Proceeding.

SUMMARY: In the Notice of Proposed Rulemaking issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (June 5, 1979 (44 FR 33099, June 8, 1979)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with respect to an exemption from incremental pricing for load-balancing facilities which have the capability to burn oil. Based upon a review of the comments, the Commission has determined not to institute a rulemaking proceeding in this matter. Thus, the Commission hereby gives notice that Docket No. RM79-46 is terminated.

FOR FURTHER INFORMATION CONTACT: Barbara K. Christin, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street NE., Washington, D.C. 20426, (202) 357-8033.

Issued September 28, 1979.

I. Background

In the Notice of Proposed Rulemaking issued in Docket No. RM79-14, *Regulations Implementing the Incremental Pricing Provisions of the Natural Gas Policy Act of 1978* (June 5, 1979 (44 FR 33099, June 8, 1979)), the Federal Energy Regulatory Commission (Commission) announced the opening of a docket to receive comments on whether a rulemaking proceeding should be established with respect to an exemption from incremental pricing for load-balancing facilities which have the capability to burn oil. Such an exemption was discussed at pp. 11-16 of the June 5th Notice (pp. 33100-33101 in the **Federal Register**).

On July 3, 1979, a Notice of Opportunity to comment on whether a Rulemaking Proceeding should be Established (44 FR 40898, July 13, 1979) was issued for the purpose of providing further public notice of the announcement which was included in the Docket No. RM79-14 Notice of Proposed Rulemaking. Comments were due no later than August 1, 1979.

Sixteen comments were received in this docket. A list of those commenting is attached to this notice as an Appendix. Based upon a review of these comments and its own analysis, the Commission has determined not to institute a rulemaking proceeding in this matter. Thus, the Commission hereby gives notice that no rulemaking proceeding will be established and Docket No. RM79-46 is terminated.

II. Discussion

Thirteen of the sixteen comments received in this docket requested the institution of a rulemaking proceeding to exempt from the incremental pricing program all load-balancing facilities which have the capability to burn oil. Nine of these comments expressed concern that, if load-balancing facilities which have the capability to burn oil are subject to incremental pricing, there will be a potential for those facilities to shift from the use of gas to the use of oil.

Many comments pointed out that the price of gas to load-balancing facilities is often lower than to other customers because the service is usually interruptible. These lower prices are what makes the gas service attractive. If the price should be raised—via incremental pricing surcharges—there would be little economic reason for these industrial facilities to use natural gas when it is available. If substantial switching (to oil) were to occur, the result could be higher prices to high priority customers because there would be fewer industrial users to share the fixed costs of operating a pipeline system. This result, the commenters argue, would be contrary to the objectives of Title II of the NGPA.

The facilities affected by the first phase of the incremental pricing program are largely those which have alternate fuel capability. A substantial number of these facilities, the Commission believes, are load-balancing facilities. To grant them an exemption from the incremental pricing program would allow the very users whom Congress intended should bear incremental surcharges to be shielded from the impact of the first phase of the incremental pricing program.

Furthermore, the alternative fuel price ceiling applicable to most of the load-balancing facilities with oil-burning capacity will probably be set at the No. 6 fuel oil price, since it is the Commission's belief that these facilities generally have No. 6 capability. In any event, however, the ceiling price applicable to an incrementally priced facility, determined in accordance with the methodology discussed in the final rule in Docket No. RM79-21 (*Regulations Implementing Alternative Fuel Cost Ceilings on Incremental Pricing Under the Natural Gas Policy Act of 1978*), will be set low enough that the load-balancing facilities which have the capability to burn oil should not have an economic reason to switch from gas to oil as a result of the incremental pricing program.

Two comments suggested that the applicable alternative fuel price ceiling be lowered by 10 percent for load-balancing facilities which have the capability to burn oil. Again the Commission emphasizes that the methodology set forth in Docket No. RM79-21 for setting the price of No. 6 fuel oil will result in a ceiling price which should be very close to, if not lower than, the price any load-balancing facility with oil-burning capability would pay for oil. Thus, no further adjustments should be needed.

In addition, the characteristics and effects of load-balancing on rate structures vary from system to system. The American Gas Association emphasized in its comments that load-balancing is not a concept susceptible to uniform national treatment. It is possible that the benefits of some load-balancing sales may diminish for certain distribution companies if there is no exemption from incremental pricing for such sales. That possibility, however, does not justify a blanket exemption for all load-balancing facilities which have the capability to burn oil.

Congress has given the Commission, in sections 206(d) and 502(c) of the NGPA, the flexibility to provide relief when necessary. The Commission believes that the regulations which implement these two provisions, 18 CFR 282.206 and 18 CFR 1.41, provide adequate avenues for any party to request administrative relief on a case-by-case basis. An adjustment under § 1.41 in the form of an exception to the incremental pricing regulations in Part 282 may be granted upon a showing by the applicant that relief is necessary to prevent special hardship, inequity or unfair distribution of burdens. The Commission has the capability of rapidly processing a § 1.41 petition for relief and believes it will be able to handle any such petitions in an expeditious and equitable manner.

However, the Commission does not intend that the § 1.41 procedures should provide the vehicle for generalized challenges to Title II of the NGPA and the regulations promulgated thereunder. The § 1.41 procedures have been adopted by the Commission simply to provide an avenue of administrative relief for parties which are uniquely affected by Commission regulations, and not to provide an arena for inquiries into policy questions of broad applicability.

The three comments which opposed the establishment of a rulemaking proceeding in this docket stated reasons generally consistent with those described above for not proceeding any further with a rulemaking to exempt load-balancing facilities which have the capability to burn oil.

For the reasons stated in this notice, a rulemaking regarding an exemption from incremental pricing for load-balancing facilities which have the capability to burn oil will not be initiated. The Commission hereby gives notice that Docket No. RM79-46 is terminated.

By direction of the Commission.

Lois D. Cashell,

Acting Secretary.

Appendix

Following is a list of those who submitted comments in Docket No. RM79-46:

The American Gas Association
Associated Gas Distributors
Brooklyn Union Gas Company
Connecticut Natural Gas Corporation
Mountain Fuel Supply Company
Natural Gas Pipeline Company of America
Northern Indiana Public Service Company
The Peoples Gas Light and Coke Company
Philadelphia Gas Works
The Process Gas Consumers Group, the Georgia Industrial Gas Group, and The American Iron and Steel Institute
Public Service Company of Colorado
State of Wisconsin Public Service Commission
Southern Company Services, Inc.
The United Distribution Companies
The Wisconsin Distributor Group
Wisconsin Gas Company

[FR Doc. 79-30781 Filed 10-3-79; 8:45 am]
BILLING CODE 6450-01-M

federal register

Friday
October 5, 1979

Part V

Environmental Protection Agency

Automobile and Light-Duty Truck Surface Coating Operations; Standards of Performance and Addition to the List of Categories of Stationary Sources

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL-1285-4]

Automobile and Light-Duty Truck Surface Coating Operations; Standards of Performance

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Standards of performance are proposed to limit emissions of volatile organic compounds (VOC) from new, modified, and reconstructed automobile and light-duty truck surface coating operations within assembly plants. Three new test methods are also proposed. Reference Method 24 (Candidate 1 or Candidate 2) would be used to determine the VOC content of coating materials, and Reference Method 25 would be used to determine the percentage reduction of VOC emissions achieved by add-on emission control devices.

The standards implement the Clean Air Act and are based on the Administrator's determination that automobile and light-duty truck surface coating operations within assembly plants contribute significantly to air pollution. The intent is to require new, modified, and reconstructed automobile and light-duty truck surface coating operations to use the best demonstrated system of continuous emission reduction, considering costs, nonair quality health, and environmental and energy impacts.

A public hearing will be held to provide interested persons an opportunity for oral presentation of data, views, or arguments concerning the proposed standards.

DATES: *Comments.* Comments must be received on or before December 14, 1979.

Public Hearing. The public hearing will be held on November 9, 1979, at 9 a.m.

Request to Speak at Hearing. Persons wishing to present oral testimony should contact EPA by November 2, 1979

ADDRESSES: *Comments.* Comments should be submitted to: Central Docket Section (A-130), Attention: Docket Number A-79-05, U.S. Environmental Protection Agency, 401 M Street SW., Washington, D.C. 20460.

Public Hearing. The public hearing will be held at National Environmental Resource Center (NERC), Rm. B-102, R.T.P., N.C. Persons wishing to present oral testimony should notify Ms. Shirley Tabler, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5421.

Background Information Document. The Background Information Document (BID) for the proposed standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Automobile and Light-Duty Truck Surface Coating Operations—Background Information for Proposed Standards," EPA-450/3-79-030.

Docket. The Docket, number A-79-05, is available for public inspection and copying at the EPA's Central Docket Section, Room 2903 B, Waterside Mall, Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Proposed Standards

The proposed standards would apply to new automobile and light-duty truck surface coating operations. Existing plants would not be covered unless they undergo modifications resulting in increased emissions or reconstructions. The proposed standards would apply to each prime coat operation, each guide coat operation, and each topcoat operation within an assembly plant. Emissions of VOC from each of these operations would be limited as follows: 0.10 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from prime coat operations, 0.84 kilogram of VOC (measured as mass of carbon) per liter applied coating solids from guide coat operations, 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from topcoat operations.

These proposed emission limits are based on Method 24 (Candidate 1) which determines VOC content of coatings expressed as the mass of carbon. At the time the standards were developed, it was believed that VOC emissions should be determined from carbon measurements. Method 24 (Candidate 1) was developed to measure carbon directly and thus improve the accuracy of the previously used ASTM procedure D 2369-73, which measures the mass of volatile organics indirectly. However, questions have been raised concerning the validity of using the carbon method since the ratio of mass of carbon to mass of VOC in solvents used in automotive coatings varies over a wide range. The effect which this variation might have on the standards is still being investigated. Method 24 (Candidate 2) was developed as a test method for determining VOC emissions from coating materials in terms of mass of volatile organics and is also derived from ASTM procedure D 2369-73. The proposed emission limits, based on Method 24 (Candidate 2) which measures volatile organics, are: 0.16 kilogram of VOC per liter of applied coating solids from prime coat operations, and 1.36 kilogram of VOC per liter of applied coating solids for guide coat operations, and 1.36 kilogram of VOC per liter of applied coating solids from top coat operations. In order to provide an opportunity for public comment on both test methods, both are being proposed, and the final selection of a test method will be made before promulgation, based on the comments received.

Although the emission limits are based on the use of water-based coating materials in each coating operation, they can also be met with solvent-based coating materials through the use of other control techniques, such as incineration. Exemptions are included in the proposed standards which specifically exclude annual model changeovers from consideration as modifications.

Summary of Environmental, Energy, and Economic Impacts

Environmental, energy, and economic impacts of standards of performance are normally expressed as incremental differences between the impacts from a facility complying with the proposed standard and those for one complying with a typical State Implementation Plan (SIP) emission standard. In the case of automobile and light-duty truck surface coating operations, the incremental differences will depend on the control levels that will be required by revised SIP's. Revisions to most SIP's are currently in progress.

Most existing automobile and light-duty truck surface coating operations are located in areas which are considered nonattainment areas for purposes of achieving the National Ambient Air Quality Standard (NAAQS) for ozone. New facilities are expected to locate in similar areas. States are in the process of revising their SIP's for these areas and are expected to include revised emission limitations for automobile and light-duty truck surface coating operations in their new SIP's. In revising their SIP's the States are relying on the control techniques guideline document, "Control of Volatile Organic Emissions from Existing Stationary Sources—Volume II: Surface Coating of Cans, Coil, Paper, Fabrics, Automobiles and Light-Duty Trucks" (EPA-450/2-77-088 [CTG]).

Since control technique guidelines are not binding, States may establish emission limits which differ from the guidelines. To the extent States adopt the emission limits recommended in the control techniques guideline document as the basis for their revised SIP's, the proposed standards of performance would have little environmental, energy, or economic impacts. The actual incremental impacts of the proposed standards of performance, therefore, will be determined by the final emission limitations adopted by the States in their revised SIP's. For the purpose of this rulemaking, however, the environmental, energy, and economic impacts of the proposed standards have been estimated based on emission limits contained in existing SIP's.

In addition to achieving further reductions in emissions beyond those required by a typical SIP, standards of performance have other benefits. They establish a degree of national uniformity to avoid situations in which some States may attract industries by relaxing air pollution standards relative to other States. Further, standards of performance improve the efficiency of case-by-case determinations of best available control technology (BACT) for facilities located in attainment areas, and lowest achievable emission rates (LAER) for facilities located in nonattainment areas, by providing a starting point for the basis of these determinations. This results from the process for developing a standard of performance, which involves a comprehensive analysis of alternative emission control technologies and an evaluation and verification of emission test methods. Detailed cost and economic analyses of various regulatory alternatives are presented in the supporting documents for standards of performance.

Based on emission control levels contained in existing SIP's, the proposed standards of performance would reduce emissions of VOC from new, modified, or reconstructed automobile and light-duty truck surface coating operations by about 80 percent. National emissions of VOC would be reduced by about 4,800 metric tons per year by 1983.

Water pollution impacts of the proposed standards would be relatively small compared to the volume and quality of the wastewater discharged from plants meeting existing SIP levels. The proposed standards are based on the use of water-based coating materials. These materials would lead to a slight increase in the chemical oxygen demand (COD) of the wastewater discharged from the surface coating operations within assembly plants. This increase in COD, however, is not great enough to require additional wastewater treatment capacity beyond that required in existing assembly plants using solvent-based surface coating materials.

The solid waste impact of the proposed standards would be negligible compared to the amount of solid waste generated by existing assembly plants. The solid waste generated by water-based coatings, however, is very sticky, and equipment cleanup is more time consuming than for solvent-based coatings. Solid wastes from water-based coatings do not present any special disposal problems since they can be disposed of by conventional landfill procedures.

National energy consumption would be increased by the use of water-based coatings to comply with the proposed standards. The equivalent of an additional 18,000 barrels of fuel oil would be consumed per year at a typical assembly plant. This is equivalent to an increase of about 25 percent in the energy consumption of a typical surface coating operation. National energy consumption would be increased by the equivalent of about 72,000 barrels of fuel oil per year in 1983. This increase is based on the projection that four new assembly plants will be built by 1983.

The proposed standards would increase the capital and annualized costs of new automobile and light-duty truck surface coating operations within assembly plants. Capital costs for the four new facilities planned by 1983 would be increased by approximately $19 million as a result of the proposed standards. The incremental capital costs for control represent about 0.2 percent of the $10 billion planned for capital expenditures. The corresponding annualized costs would be increased by approximately $9 million in 1983. The price of an automobile or light-duty truck manufactured at a new plant which complies with the proposed standards of performance would be increased by less than 1 percent. This is considered to be a reasonable control cost.

Modifications and Reconstructions

During the development of the proposed standards, the automobile industry expressed concern that changes to assembly plants made only for the purpose of annual model changeovers would be considered a modification or reconstruction as defined in the Code of Federal Regulations, Title 40, Parts 60.14 and 60.15 (40 CFR 60.14 and 60.15). A modification is any physical or operational change in an existing facility which increases air pollution from that facility. A reconstruction is any replacement of components of an existing facility which is so extensive that the capital cost of the new components exceeds 50 percent of the capital cost of a new facility. In general, modified and reconstructed facilities must comply with standards of performance. According to the available information, changes to coating lines for annual model changeovers do not cause emissions to increase significantly. Further, these changes would normally not require a capital expenditure that exceeds the 50 percent criterion for reconstruction. Hence, it is very unlikely that these annual facility changes would be considered either modifications or reconstructions. Therefore, the proposed standards state that changes to surface coating operations made only to accommodate annual model changeovers are not modifications or reconstructions. In addition, by exempting annual model changeovers, enforcement efforts are greatly reduced with little or no adverse environmental impact.

Selection of Source and Pollutants

VOC are organic compounds which participate in atmospheric photochemical reactions or are measured by Reference Methods 24 (Candidate 1 or Candidate 2) and 25. There has been some confusion in the past with the use of the term "hydrocarbons." In addition to being used in the most literal sense, the term "hydrocarbons" has been used to refer collectively to all organic chemicals. Some organics which are photochemical oxidant precursors are not hydrocarbons (in the strictest definition) and are not always used as solvents. For purposes of this discussion, organic compounds include all compounds of carbon except carbonates, metallic carbides, carbon monoxide, carbon dioxide and carbonic acid.

Ozone and other photochemical oxidants result in a variety of adverse impacts on health and welfare, inducing impaired respiratory function, eye irritation, deterioration of materials such as rubber, and necrosis of plant tissue. Further information on these effects can be found in the April 1978 EPA document "Air Quality Criteria for Ozone and Other Photochemical Oxidants," EPA-600/8-78-004. This document can be obtained from the EPA library (see Addresses Section).

Industrial coating operations are a major source of air pollution emissions of VOC. Most coatings contain organic solvents which evaporate upon drying of the coating, resulting in the emission of VOC. Among the largest individual operations producing VOC emissions in the industrial coating category are automobile and light-duty truck surface coating operations. Since the surface coating operations for automobiles and light-duty trucks are very similar in nature, with line speed being the primary difference, they are being considered together in this study. Automobile and light-duty truck manufacturers employ a variety of surface coatings, most often enamels and lacquers, to produce the protective and decorative finishes of their product. These coatings normally use an organic solvent base, which is released upon drying.

The "Priority List for New Source Performance Standards under the Clean Air Act Amendments of 1977," which was promulgated in 40 CFR 60.16, 44 FR 49222, dated August 21, 1979, ranked sources according to the impact that standards promulgated in 1980 would have on emissions in 1990. Automobile and light-duty truck surface coating operations rank 27 out of 59 on this list of sources to be controlled.

The surface coating operation is an integral part of an automobile or light-duty truck assembly plant, accounting for about one-quarter to one-third of the total space occupied by a typical assembly plant. Surface coatings are applied in two main steps, prime coat and topcoat. Prime coats may be water-based or organic solvent-based. Water-based coatings use water as the main carrier for the coating solids, although these coatings normally contain a small amount of organic solvent. Solvent-based coatings use organic solvent as the coating solids carrier. Currently about half of the domestic automobile and light-duty truck assembly plants use water-based prime coats.

Where water-based prime coating is used, it is usually applied by EDP. The EDP coat is normally followed by a "guide coat," which provides a suitable surface for application of the topcoat. The guide coat may be water-based or solvent-based.

Automobile and light-duty truck topcoats presently being used are almost entirely solvent-based. One or more applications of topcoats are applied to ensure sufficient coating thinkness. An oven bake may follow each topcoat application, or the coating may be applied wet on wet.

In 1976, nationwide emissions of VOC from automobile and light-duty truck surface coating operations totaled about 135,000 metric tons. Prime and guide coat operations accounted for about 50,000 metric tons with the remaining 85,000 metric tons being emitted from topcoat operations. This represents almost 15 percent of the volative organic emissions from all industrial coating operations.

VOC comprise the major air pollutant emmitted by automobile and light-duty truck assembly plants. Technology is available to reduce VOC emissions and thereby reduce the formation of ozone and other photochemical oxidants. Consequently, automobile and light-duty truck surface coating operations have been selected for the development of standards of performance.

Selection of Affected Facilities

The prime coat, guide coat, and topcoat operations usually account for more than 80 percent of the VOC emissions from autombile and light-duty truck assembly plants. The remaining VOC emissions result from final topcoat repair, cleanup, and coating of various small component parts. These VOC emission sources are much more difficult to control than the main surface coating operations for several reasons. First, water-based coatings cannot be used for final topcoat repair, since the high temperatures required to cure water-based coatings may damage heat sensitive components which have been attached to the vehicle by this stage of production. Second, the use of solvents is required for equipment cleanup procedures. Third, add-on controls, such as incineration, cannot be used effectively on these cleanup operations because they are composed of numerous small operations located throughout the plant. Since prime coat, guide coat, and topcoat operations account for the bulk of VOC emissions from autombile and light-duty truck assembly plants, and control techniques for reducing VOC emissions from these operations are demonstrated, they have been selected for control by standards of performance.

The "affected facility" to which the proposed standards would apply could be designated as the entire surface coating line or each individual surface coating operation. A major consideration in selecting the affected facility was the potential effect that the modification and reconstruction provisions under 40 CFR 60.14 and 60.15, which apply to all standards of performance, could have on existing assembly plants. A modification is any physical or operational change in an existing facility which increases air pollution from that facility. A reconstruction is any replacement of components of an existing facility which is so extensive that the capital cost of the new componensts exceeds 50 percent of the capital cost of a new facility. For standards of performance to apply, EPA must conclude that it is technically and economically feasible for the reconstructed facility to meet the standards.

Many automobile and light-duty truck assembly plants that have a spray prime coat system will be switching to EDP prime coat systems in the future to reduce VOC emissions to comply with revised SIP's. The capital cost of this change could be greater than 50 percent of the capital cost of a new surface coating line. If the surface coating line were chosen as the affected facility, and if this switch to an EDP prime coat system were considered a reconstruction of the surface coating line, all surface coating operations on the line would be required to comply with the proposed standards. Most plants would be reluctant to install an EDP prime coat system to reduce VOC emissions if, by doing so, the entire surface coating line might then be required to comply with standards of performance. By designating the prime coat, guide coat, and topcoat operations as separate affected facilities, this potential problem is avoided. Thus, each surface coating operation (i.e., prime coat, guide coat, and topcoat) has been selected as an affected facility in the proposed standards.

Selection of Best System of Emission Reduction

VOC emissions from automobile and light-duty truck surface coating operations can be controlled by the use of coatings having a low organic solvent content, add-on emissions control devices, or a combination of the two. Low organic solvent coatings consist of water-based enamels, high solids enamels, and powder coatings. Add-on emission control devices consist of such techniques as incineration and carbon adsorption.

Control Technologies

Water-based coating materials are applied either by conventional spraying or by EDP. Application of coatings by EDP involves dipping the automobile or truck to be coated into a bath containing a dilute water solution of the coating material. When charges of opposite polarity are applied to the dip tank and vehicle, the coating material deposits on the vehicle. Most EDP systems presently in use are anodic systems in which the vehicle is given a positive charge.

Cathodic EDP, in which the vehicle is negatively charged, is a new technology which is expanding rapidly in the automotive industry. Cathodic EDP provides better corrosion resistance and requires lower cure temperatures than anodic systems. Cathodic EDP systems are also capable of applying better coverage on deep recesses of parts.

The prime coat is usually followed by a spray application of an intermediate coat, or guide coat, before topcoat application. The guide coat provides the added film thickness necessary for sanding and a suitable surface for topcoat application. EDP can only be used if the total film thickness on the metal surface does not exceed a limiting value. Since this limiting thickness is about the same as the thickness of the prime coat, spraying has to be used for guide coat and topcoat application of water-based coatings.

Currently, nearly half of domestic automobile and light-duty truck assembly plants use EDP for prime coat application, but only two domestic plants use water-based coating for guide coat and topcoat applications.

Coatings whose solids content is about 45 to 60 percent are being developed by a number of companies. When these coatings are applied at high transfer efficiency rates, VOC emissions are significantly less than emissions from existing solvent-based systems. While these high solids coatings could be used in the automotive industry, certain problems must be overcome. The high working viscosity of these coatings makes them unsuitable for use in many existing application devices. In addition, this high viscosity can produce an "orange peel," or uneven, surface. It also makes these coatings unsuitable for use with metallic finishes. Metallic finishes, which account for about 50 percent of domestic demand, are produced by adding small metal flakes to the paint. As the paint dries, these flakes become oriented parallel to the surface. With high solids coatings, the viscosity of the paint prevents movement of the flakes, and they remain randomly oriented, producing a rough surface. However, techniques such as heated application are being investigated to reduce these problems, and it is expected that by 1982 high solids coatings will be considered technically demonstrated for use in the automotive industry.

Powder coatings are a special class of high solids coatings that consist of solids only. They are applied by electrostatic spray and are being used on a limited basis for topcoating automobiles, both foreign and domestic. The use of powder coatings is severely limited, however, because metallic finishes cannot be applied using powder. As with other high solids coatings, research is continuing in the use of powder coatings for the automotive industry.

Thermal incineration has been used to control VOC emissions from bake ovens in automobile and light-duty truck surface coating operations because of the fairly low volume and high VOC concentration in the exhaust stream. Incineration normally achieves a VOC emission reduction of over 90 percent. Thermal incinerators have not, however, been used for control of spray booth VOC emissions. Typically, the spray booth exhaust stream is a high volume stream (95,000 to 200,000 liters per second) which is very low in concentration of VOC (about 50 ppm). Thermal incineration of this exhaust stream would require a large amount of supplemental fuel, which is its main drawback for control of spray booth VOC emissions. There are no technical problems with the use of thermal incineration.

Catalytic incineration permits lower incinerator operating temperatures and, therefore, requires about 50 percent less energy than thermal incineration. Nevertheless, the energy consumption would still be high if catalytic incineration were used to control VOC emissions from a spray booth. In addition, catalytic incineration allows the owner or operator less choice in selecting a fuel; it requires the use of natural gas to preheat the exhaust gases, since oil firing tends to foul the catalyst. While catalytic incineration is not currently being employed in automobile and light-duty truck surface coating operations for control of VOC emissions, there are no technical problems which would preclude its use on either bake oven or spray booth exhaust gases. The primary limiting factor is the high energy consumption of natural gas, if catalytic incineration is used to control emissions from spray booths.

Carbon adsorption has been used successfully to control VOC emissions in a number of industrial applications. The ability of carbon adsorption to control VOC emissions from spray booths and bake ovens in automobile and light-duty truck surface coating operations, however, is uncertain. The presence of a high volume, low VOC exhaust stream from spray booths would require carbon adsorption units much larger than any that have ever been built. For bake ovens in automobile and light-duty truck surface coating operations, a major impediment to the use of carbon adsorption is heat. The high temperature of the bake oven exhaust stream would require the use of refrigeration to cool the gas stream before it passes through the carbon bed. Carbon adsorption, therefore, is not considered a demonstrated technology at this time for controlling VOC emissions from automobile and light-duty truck surface coating operations. Work is continuing within the automotive industry on efforts to apply carbon adsorption to the control of VOC emissions, however, and it may become a demonstrated technology in the near future.

Regulatory Options

Water-based coatings and incineration are two well-demonstrated and feasible techniques for controlling emissions of VOC from automobile and light-duty truck surface coating operations. Based upon the use of these two VOC emission control techniques, the following two regulatory options were evaluated.

Regulatory Option I includes two alternatives which achieve essentially equivalent control of VOC emissions. Alternative A is based on the use of water-based prime coats, guide coats, and topcoats. The prime coat would be applied by EDP. Since the guide coat is essentially a topcoat material, guide coat emission levels as low as those achieved by water-based topcoats should be possible through a transfer of technology from topcoat operations to guide coat operations. Alternative B is based on the use of a water-based prime coat applied by EDP and solvent-based guide coats and topcoats. Incineration of the exhaust gas stream from the topcoat spray booth and bake oven would be used to control VOC emissions under this alternative.

Regulatory Option II is based on the use of a water-based prime coat applied by EDP and solvent-based guide coats and topcoats. In this option, the exhaust gas streams from both the guide coat and topcoat spray booths and bake ovens would be incinerated to control VOC emissions.

Environmental, Energy, and Economic Impacts

Standards based on Regulatory Option I would lead to a reduction in VOC emissions of about 80 percent, and standards based on Regulatory Option II would lead to a reduction in emissions of about 90 percent, compared to VOC emissions from automobile and light-duty truck surface coating operations controlled to meet current SIP requirements. Growth projections indicate there will be four new automobile and light-duty truck assembly lines constructed by 1983. Very few, if any, modifications or reconstructions are expected during this period. Based on these projections, national VOC emissions in 1983 would be reduced by about 4,800 metric tons with standards based on Regulatory Option I and about 5,400 metric tons with standards based on Regulatory Option II. Thus, both regulatory options would result in a significant reduction in VOC emissions from automobile and light-duty truck surface coating operations.

With regard to water pollution, standards based on Regulatory Option II would have essentially no impact. Similarly, standards based on Regulatory Option I(B) would have no water pollution impact. Standards based on Regulatory Option I(A), however, would result in a slight increase in the chemical oxygen demand (COD) of the wastewater discharged from automobile and light-duty truck surface coating operations within assembly plants. This increase is due to water-miscible solvents in the water-based guide coats and topcoats which become dissolved in the wastewater. The increase in COD of the wastewater, however, would be small relative to current COD levels at plants using solvent-based surface coatings and meeting existing SIP's. In addition, this increase would not require the installation of a larger wastewater treatment facility than would be built for an assembly plant which used solvent-based surface coatings.

The solid waste impact of the proposed standards would be negligible. The volume of sludge generated from water-based surface coating operations is approximately the same as that generated from solvent-based surface coating operations. The solid waste generated by water-based coatings, however, is very sticky, and equipment cleanup is more time consuming than for solvent-based coatings. Sludge from either type of system can be disposed of by conventional landfill procedures without leachate problems.

With regard to energy impact, standards based on Regulatory Option I(A) would increase the energy consumption of surface coating operations at a new automobile or light-duty truck assembly plant by about 25 percent. Regulatory Option I(B) would cause an increase of about 150 to 425 percent in energy consumption. Standards based on Regulatory Option II would result in an increase of 300 to 700 percent in the energy consumption of surface coating operations at a new automobile or light-duty truck assembly plant. The range in energy consumption for those options which are based on use of incineration reflects the difference between catalytic and thermal incineration.

The relatively high energy impact of standards based on Regulatory Option I(B) and Regulatory Option II is due to the large amount of incineration fuel needed. Standards based on Regulatory Option II would increase energy consumption at a new automobile and light-duty truck assembly plant by the equivalent of about 200,000 to 500,000 barrels of fuel oil per year, depending upon whether catalytic or thermal incineration was used. Standards based on Regulatory Option I(B) would increase energy consumption by the equivalent of about 100,000 to 300,000 barrels of fuel oil per year.

Standards based on Regulatory Option I(A) would increase the energy consumption of a typical new automobile and light-duty truck assembly plant by the equivalent of about 18,000 barrels of fuel oil per year. Approximately one-third of this increase in energy consumption is due to the use of air conditioning, which is necessary with the use of water-based coatings, and the remaining two-thirds are due to the increased fuel required in the bake ovens for curing water-based coatings.

Growth projections indicate that four new automobile and light-duty truck assembly lines (two automobile and two truck lines) will be built by 1983. Based on these projections, standards based on Regulatory Option I(A) would increase national energy consumption in 1983 by the equivalent of about 72,000 barrels of fuel oil. Standards based on Regulatory Option I(B) would increase national energy consumption in 1983 by the equivalent of 400,000 to 1,200,000 barrels of fuel oil, depending on whether catalytic or thermal incineration were used. Standards based on Regulatory Option II would increase national energy consumption in 1983 by the equivalent of 800,000 to 2,000,000 barrels of fuel oil, again depending on whether catalytic or thermal incineration were used.

The economic impacts of standards based on each regulatory option were estimated using the growth projection of four new assembly lines by 1983. Incremental control costs were determined by calculating the difference between the capital and annualized costs of new assembly plants controlled to meet Regulatory Options I(A), I(B), and II, respectively, with the corresponding costs for new plants designed to comply with existing SIP's. Of the four assembly plants projected by 1983, two were assumed to be lacquer lines and the other two enamel lines. There are basic design differences between these two types of surface coatings which have a substantial impact on the magnitude of the costs estimated to comply with standards of performance. Lacquer surface coating operations, for example, require much larger spray booths and bake ovens than enamel surface coating operations. Water-based systems also require large spray booths and bake ovens; thus, the incremental capital cost of installing a water-based system in a plant which would otherwise have used a lacquer system is relatively low. The incremental capital costs differential, however, would be much larger if the plant would have been designed for an enamel system.

Tables 1 and 2 summarize the economic impacts of the proposed standards on plants of typical sizes. Table 1 presents the incremental costs of the various control options for a plant which would have used solvent-based lacquers. Table 2 presents similar costs for plants which would have been designed to use solvent-based enamels. Though these tables present incremental costs for passenger car plants, light-duty truck plants would have similar cost differentials. In all cases, it is assumed the plants would install a water-based EDP prime system in the absence of standards of performance. Therefore, no incremental costs associated with EDP prime coat operations are included in the costs presented in Tables 1 and 2. A nominal production rate of 55 passenger cars per hour was assumed for both plants. Tables 1 and 2 show incremental capitalized and annualized costs per vehicle produced at each new facility. The manufacturers would probably distribute these incremental costs over their entire annual production to arrive at purchase prices for the automobiles and light-duty trucks.

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Table 1. INCREMENTAL CONTROL COSTS[a]

(Compared to the Costs of a Lacquer Plant)

	Regulatory Options				
	I(A)	I(B)		II	
	Water-Based Coatings	Thermal	Catalytic	Thermal	Catalytic
Capital Cost of Control Alternative	$ 720,000	$11,800,000	$15,000,000	$12,800,000	$16,200,000
Annualized Cost of Control Alternative	$1,550,000	$14,500,000	$10,700,000	$15,500,000	$11,500,000
Incremental Cost/Vehicle Produced at this Facility	$7.34	$68.66	$50.66	$73.39	$54.45

[a]Assumes a line speed of 55 vehicles per hour and an annual production of 211,200 vehicles.

Table 2. INCREMENTAL CONTROL COSTS[a]

(Compared to the Costs of an Enamel Plant)

	Regulatory Options				
	I(A)	I(B)		II	
	Water-Based Coatings	Thermal	Catalytic	Thermal	Catalytic
Capital Cost of Control Alternative	$10,300,000	$ 4,630,000	$ 5,850,000	$ 5,640,000	$ 7,000,000
Annualized Cost of Control Alternative	$ 3,640,000	$ 5,620,000	$ 4,150,000	$ 6,610,000	$ 4,890,000
Incremental Cost/Vehicle Produced at this Facility	$17.23	$26.61	$19.65	$31.30	$23.15

[a]Assumes a line speed of 55 vehicles per hour and an annual production of 211,200 vehicles.

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Incremental capital costs for suing incineration to reduce VOC emissions from solvent-based lacquer plants to levels comparable to water-based plants are much larger than they are for using incineration on a solvent-based enamel plant. This large difference in costs occurs because lacquer plants have larger spray booth and bake oven areas than enamel plants and, therefore, a larger volume of exhaust gases. Since larger incineration units are required, the incremental capital costs of using incineration to control VOC emissions from a solvent-based lacquer plant are about 15 to 25 times greater than they are for using water-based coatings. Similarly, energy consumption is much greater; hence, the annualized costs of using incineration are about 10 times greater than they are for using water-based coatings.

On the other hand, the incremental capital costs of controlling VOC emissions from new solvent-based enamel plants by the use of incineration are only about one-half the incremental capital costs between a new solvent-based enamel plant and a new water-based plant. Due to the energy consumption associated with incinerators, however, the incremental annualized costs of using incineration with solvent-based enamel coatings could vary from as little as 15 percent more to as much as 90 percent more than the annualized costs of using water-based coatings.

While the incremental capital costs of building a plant to use water-based coatings can be larger or smaller than the costs of using incineration, depending upon whether a solvent-based lacquer plant or a solvent-based enamel plant is used as the starting point, the annualized costs of using water-based coatings are always less than they are for using incineration. This is due to the large energy consumption of incineration units compared to the energy consumption of water-based coatings.

Since the incremental annualized costs are less with Regulatory Option I(A) than with Regulatory Option I(B), it is assumed in this analysis that Regulatory Option I(A) would be incorporated at any new, modified, or reconstructed facility to comply with standards based on Regulatory Option I. As noted, four new assembly plants are expected to be built by 1983. The incremental capital cost to the industry for these plants to comply with standards based on Regulatory Option I would be approximately $19 million. The corresponding incremental annualized costs would be about $9 million in 1983. If standards are based on Regulatory Option II, it is expected that the industry would choose catalytic incineration because its annualized costs are lower than those for thermal incineration. Based this assumption, the incremental capital costs for the industry under Regulatory Option II would be approximately $42 million, and the incremental annualized costs by 1983 would be about $30 million. For standards based on either Regulatory Option I or Regulatory Option II, the increase in the price of an automobile or light-duty truck that is manufactured at one of the new plants would be less than 1 percent of the base price of the vehicle.

Best System of Emission Reduction

Both Regulatory Options I and II achieve a significant reduction in VOC emissions compared to automobile and light-duty truck assembly plants controlled to comply with existing SIP's, and neither option creates a significant adverse impact on other environmental media. In terms of energy consumption, standards based on Regulatory Option II would have as much as 10 to 25 times the adverse impact on energy consumption as standards based on Regulatory Option I, while only achieving 10 to 15 percent more reductions in VOC emissions. The costs of standards based on Regulatory Option II range from two to three times the costs of standards based on Regulatory Option I. Thus, Regulatory Option I(A), water-based coatings, was selected as the best system of continuous emission reduction, considering costs and nonair quality health, and environmental and energy impacts.

Although water-based coatings are considered to be the best system of emission reduction at the present time, it is very likely that plants built in the future will use other systems to control VOC emissions, such as high solids coatings and powder coatings. High solids coatings applied at high transfer efficiencies are capable of achieving equivalent emission reductions and are expected to be less costly and require less total energy than water-based systems. These high solids coatings are expected to be available by 1982 and will probably be used by most new sources to comply with the VOC emission limitations. Powder coatings are also expected to be available in the future but are not demonstrated at this time.

Selection of Format for the Proposed Standards

A number of different formats could be selected to limit VOC emissions from automobile and light-duty truck surface coating operations. The format ultimately selected must be compatible with any of the three different control systems that could be used to comply with the proposed standards. One control system is the use of water-based coating materials in the prime coat, guide coat, and topcoat operations. Another control system is the use of solvent-based coating materials and add-on VOC emission control devices such as incineration. The third control system consists of the use of high solids coatings. Although the coatings to be used in this system are not demonstrated at this time, research is continuing toward their development; hence, they may be used in the future.

The formats considered were emission limits expressed in terms of (1) concentration of emissions in the exhaust gases discharged to the atmosphere; (2) mass emissions per unit of production; or (3) mass emissions per volume of coating solids applied.

The major advantage of the concentration format is its simplicity of enforcement. Direct emission measurements could be made using Reference Method 25. There are, however, two significant drawbacks to the use of this format. Regardless of the control approach chosen, emission testing would be required for each stack exhausting gases from the surface coating operations (unless the owner or operator could demonstrate to the Administrator's satisfaction that testing of representative stacks would give the same results as testing all the stacks). This testing would be time consuming and costly because of the large number of stacks associated with automobile and light-duty truck surface coating operations. Another potential problem with this format is the ease of circumventing the standards by the addition of dilution air. It would be extremely difficult to determine whether diluted air was being added intentionally to reduce the concentration of VOC emissions in the gases discharged to the atmosphere, or whether the air was being added to the application or drying operation to optimize performance and maintain a safe working space.

A format of mass VOC emissions per unit of production relates emissions to individual plant production on a direct basis. Where water-based coatings are used, the average VOC content of the coating materials could be determined by using Reference Method 24 (Candidate 1 or Candidate 2). The volume of coating materials used and the percent solids could be determined from purchase records. VOC emissions could then be calculated by multiplying the VOC content of the coating materials by the volume of coating materials used in a given time period and by the percentage of solids, and dividing the result by the number of vehicles produced in that time period. This would provide a VOC emission rate per unit of production. Consequently, procedures to determine compliance would be direct and straightforward, although very time consuming. This procedure would also require data collection over an excessively long period of time.

Where solvent-based coatings were used with add-on emission control devices, stack emission tests could be performed to determine VOC emissions. Dividing VOC emissions by the number of vehicles produced would again yield VOC emissions per unit of production. This format, however, would not account for differences in surface coating requirements for different vehicles caused by size and configuration. In addition, manufactureres of larger vehicles would be required to reduce VOC emissions more than manufacturers of smaller vehicles.

A format of mass of VOC emissions per volume of coating solids applied also has the advantage of not requiring stack emission testing unless add-on emission control devices rather than water-based coatings are used to comply with the standards. The introduction of dilution air into the exhaust stream would not present a problem with this format. The problem of varying vehicle sizes and configurations would be eliminate since the format is in terms of volume of applied solids regardless of the surface area or number of vehicles coated. This format would also allow flexibility in selection of control systems, for it is usable with any of the control methods. Since this format overcomes the varying dilution air and vehicle size problems inherent with the other formats, it has been selected as the format for the proposed standards. In order to use a format which is in terms of applied solids, the transfer efficiency of the application devices must be considered. Transfer efficiency is defined as the fraction of the total sprayed solids which remain on the vehicle. Transfer efficiency is an important factor because as efficiency decreases, more coating material is used and VOC emissions increase. Equations have been developed to use this format with water-based coating materials as well as with solvent-based coating materials in combination with high transfer efficiences and/or add-on emission controls devices. These equations are included in the proposed standards.

Selection of Numerical Emission Limits

Numerical Emission Limits

The numerical emission limits selected for the proposed standard are:

- 0.10 kilogram of VOC per liter of applied coating solids from prime coat operations
- 0.84 kilogram of VOC per liter of applied coating solids from guide coat operations
- 0.84 kilogram of VOC per liter of applied coating solids from topcoat operations

In all three limits, the mass of VOC is measured as carbon in accordance with Reference Methods 24 (Candidate 1) and 25. These emission limits are based on the use of water-based coating materials in the prime coat, guide coat, and topcoat operations. Water-based coating data were obtained from plants which were using these materials as well as from the vendors who supply them. These data were used to calculate VOC emission limits using a procedure similar to proposed Method 24 (Candidate 1). A transfer efficiency of 40 percent was then applied to the values obtained for guide coat and top-coat emissions. This efficiency was determined to be representative of a well-operated air-atomized spray system. The CTG-recommended limits are based on the use of the same coating materials as the proposed standards. The limits in the CTG are expressed in pounds of VOC per gallon of coating (minus water) used in the EDP system or the spray device. The limits in these proposed standards, however, are referenced to the amount of coating solids which adhere to the vehicle body. Therefore, to compare the limits in the CTG to those proposed here, it is necessary to account for the solids content of the coating and the efficiency of applying the guide coat and topcoat to the vehicle body. Consideration of transfer efficiency is significant because the proposed standards can be met by using high solids content coating materials if the amount of overspray is kept to a minimum. Since this format provides equivalency determinations for systems using solvent-based coating materials in combination with high transfer efficiencies and/or add-on control devices, it allows flexibility in selection of control systems.

As discussed in previous sections, there are two types of EDP systems. Anodic EDP was the first type developed for use in automobile surface coating operations. Cathodic EDP is the second type and is a recent technology improvement which results in greater corrosion resistance. Consequently, nearly 50 percent of the existing EDP operations use cathodic systems, and continued changeovers from anodic to cathodic EDP are expected. Since cathodic EDP produces a coating with better corrosion resistance, the proposed standards are based on the best available cathodic EDP systems.

The coating material on which the EDP emission limit is based is presently in production use. Although this low solvent content material is currently available only in limited quantities, it is expected to be available in sufficient quantities for use in all new or modified sources before promulgation of the standard. The final promulgated standards will be based on this low solvent content material, rather than the EDP material commonly used now, if it is determined to be widely available at that time.

The emission limit for guide coat operations is based on a transfer of technology from topcoat operations. The guide coat is essentially a topcoat material, without pigmentation, and water-based topcoats are available which can comply with the proposed limits. Hence, the same emission limit is proposed for the guide coat operation as for the topcoat operation.

Because of the elevated temperatures present in the prime coat, guide coat, and topcoat bake ovens, additional amounts of "cure volatile" VOC may be emitted. These "cure volatile" emissions are present only at high temperatures and are not measured in the analysis which is used to determine the VOC content of coating materials. Cure volatile emissions, however, are believed to constitute only a small percentage of total VOC emissions. Consequently, because of the complexity of measuring and controlling cure volatile emissions, they will not be considered in determining compliance with the proposed standards.

A large number of coating materials are used in topcoat operations, and each may have a different VOC content. Hence, an average VOC content of all the coatings used in this operation would be computed to determine compliance with the proposed standards. Either of two averaging techniques could be used for computing this average. Weighted averages provide very accurate results but would require keeping records of the total volume and percent solids of each different coating used. Arithmetic averages are not always as accurate; however, they are much simpler to calculate. In the case of topcoat operations, normally 15 to 20 different coatings are used, and the VOC content for most of these coatings is in the same general range. Therefore, an arithmetic average would closely approximate the values obtained from a weighted average. An arithmetic average would be calculated by summing the VOC content of each surface coating material used in a surface coating operation (i.e., guide coat or topcoat), and dividing the sum by the number of different coating materials used. Arithmetic averages are also consistent with the approach being incorporated into some revised SIP's.

For the EDP process, however, an arithmetic average VOC content is not appropriate to determine compliance with the proposed standards. In an EDP system, the coating material applied to an automobile or light-duty truck body is replaced by adding fresh coating materials to maintain a relatively constant concentration of solids, solvent, and fluid level in the EDP coating tank. Three different types of materials are usually added in separate streams—clear resin, pigment paste, and solvent.

The clear resin and pigment paste are very low in VOC content (i.e., 10 percent or less), while the solvent is very high in VOC content (i.e., 90 percent or more). The solvent additive stream is only about 2 percent of the total volume added. Consequently, an arithmetic average of the three streams seriously misrepresents the actual amount of VOC added to the EDP coating tank. Weighted averages, therefore, were selected for determining the average VOC content of coating materials applied by EDP.

If an automobile or light-duty truck manufacturer chooses to use a control technique other than water-based coatings, the transfer efficiency of the application devices used becomes very important. As transfer efficiency decreases, more coating material is used and VOC emissions increase. Therefore transfer efficiency must be taken into account to determine equivalency to water-based coatings.

Electrostatic spraying, which applies surface coatings at high transfer efficiences, can in many industries be used with water-based coatings if the entire paint handling system feeding the atomizers is insulated electically from ground. Otherwise, the high conductivity of the water involved would ground out and make ineffective the electrostatic effect. In the case of the coating of automobiles, however, because of the larger number of colors involved, the high frequency and speed of color changes required, the large volume of coatings consumed per shift, and the large number of both automatic and manual atomizers involved, it is not technically feasible to combine water-based coatings and electrostatic methods for reasons of complexity, cost, and personnel comfort. Consequently, water-based surface coatings are applied by air-atomized spray systems at a transfer efficiency of about 40 percent. The numerical emission limits included in the proposed standards were developed based on the use of water-based surface coatings applied at a 40 percent transfer efficiency. Therefore, if surface coatings are applied to a greater than 40 percent transfer efficiency, surface coatings with higher VOC contents may be used with no increase in VOC emissions to the atmosphere. Transfer efficiencies for various means of applying surface coatings have been estimated, based on information obtained from industries and vendors, as follows:

Application method:	Transfer efficiency (percent)
Air Atomized Spray	40
Manual Electrostatic Spray	75
Automatic Electrostatic Spray	95
Electrodeposition (EDP)	100

These values are estimates which reflect the high side of expected transfer efficiency ranges, and therefore, are intended to be used only for the purpose of determining compliance with the proposed standards.

Frequently, more than one application method is used within a single surface coating operation. In these cases, a weighted average transfer efficiency, based on the relative volume of coating sprayed by each method, will be estimated. These situations are likely to vary among the different manufacturers and the estimates, therefore, will be subject to approval by the Administrator on a case-by-case basis.

Method of Determining Compliance

The procedure for determining compliance with the proposed standards is complicated due to the number of different control systems which may be used. The following multistep procedure would be used.

1. Determine the average VOC content per liter of coating solids of the prime coat, guide coat, and topcoat materials being used. This would require analyzing all coating materials used in each coating operation using the proposed Reference Method 24 (Candidate 1 or Candidate 2) and calculating an average VOC content for each coating operation.

2. Select the appropriate transfer efficiency for each surface coating operation from the table included in the proposed standards.

3. Calculate the mass of VOC emissions per volume of applied solids for each surface coating operation by dividing the appropriate average VOC content of the coatings (Step 1) by the transfer efficiency of the surface coating operation (Step 2). If the value obtained is lower than the emission limit included in the proposed standards, the surface coating operation would be in compliance. If the value obtained is higher than the emission limit, add-on VOC emission control would be required to comply with the proposed standards.

4. If add-on emission control is required, calculate the emission reduction efficiency in VOC emissions which is required using the equations included in the proposed standards.

5. In cases where all exhaust gases are not vented to an emission control device, determine the percentage of total VOC emissions which enter the add-on emission control device by sampling all the stacks and using the equations included in the proposed standards. Representative sampling, however, could be approved by the Administrator, on a case-by-case basis, rather than requiring sampling of all stacks for this determination.

6. Calculate the actual efficiency of the control device by determining VOC emissions before and after the device using the proposed Reference Method 25.

7. Calculate the VOC emission reduction efficiency achieved by multiplying the percentage of VOC emissions which enter the add-on VOC emission control device (Step 5) by the add-on control device efficiency (Step 6). If the resulting value of the emission reduction efficiency achieved were greater than that required (Step 4), then the surface coating operation would be in compliance.

Detailed instructions, as well as the equations to be used for these calculations, are contained in the proposed standards.

Selection of Monitoring Requirements

Monitoring requirements are generally included in standards of performance to provide a means for enforcement personnel to ensure that emission control measures adopted by a facility to comply with standards of performance are properly operated and maintained. Surface coating operations which have achieved compliance with the proposed standards without the use of add-on VOC emission control devices would be required to monitor the average VOC content (weighted averages for EDP and arithmetic averages for guide coat and topcoat) of the coating materials used in each surface coating operation. Generally, increases in the VOC content of the coating materials would cause VOC emissions to increase. These increases could be caused by the use of new coatings or by changes in the composition of existing coatings. Therefore, following the initial performance test, increases in the average VOC content of the coating materials used in each surface coating operation would have to be reported on a quarterly basis.

Where add-on control devices, such as incinerators, were used to comply with the proposed standards, combustion temperatures would be monitored. Following the initial performance test, decreases in the incinerator combustion temperature would be reported on a quarterly basis.

Performance Test Methods

Reference Method 24, "Determination of Volatile Organic Compound Content of Paint, Varnish, Lacquer, or Related Products," is proposed in two forms—Candidate 1 and Candidate 2. Candidate 1 leads to a determination of VOC content expressed as the mass of carbon. Candidate 2 yields a determination of VOC content measured as mass of volatile organics. The decision as to which Candidate will be used depends on the final format selected for the proposed standards. Reference Method 25, "Determination of Total Gaseous Nonmethane Volatile Organic Compound Emissions," is proposed as the test method to determine the percentage reduction of VOC emissions achieved by add-on emission control devices.

Public Hearing

A public hearing will be held to discuss the proposed standards in accordance with Section 307(d)(5) of the Clean Air Act. Persons wishing to make oral presentations should contact EPA at the address given above (see Addresses Section). Oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement before, during, or within 30 days after the hearing. Written statements should be addressed to "Docket" (see Addresses Section).

A verbatim transcript of the hearing and written statements will be available for public inspection and copying during normal working hours at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

Docket

The docket, containing all supporting information used by EPA to date, is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of the rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking development. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can intelligently and effectively participate in the rulemaking process. Along with the statement of basis and purpose of the promulgated rule and EPA responses to significant comments, the contents of the Docket will serve as the record in case of judicial review [Section 307(d)(a)].

Miscellaneous

As prescribed by Section 111, establishment of standards of performance for automobile and light-duty truck surface coating operations was preceded by the Administrator's determination (40 CFR 60.16, 44 FR 49222, dated August 21, 1979) that these sources contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with Section 117 of the Act, publication of these standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator welcomes comments on all aspects of the proposed regulations, including the technological issues, monitoring requirements, and the proposed test methods. Comments are requested specifically on Method 24 (Candidate 1 and Candidate 2) and the coating material used as the basis for the prime coat emission limit.

It should be noted that standards of performance for new sources established under Section 111 of the Clean Air Act reflect:

> . . . application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [Section 111(a)(1)].

Although emission control technology may be available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance because of costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act may require the imposition of a more stringent emission standard in several situations.

For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources locating in nonattainment areas (i.e., those areas where statutorily mandated health and welfare standards are being violated). In this respect, section 173 of the Act requires that new or modified sources constructed in an area which exceeds the NAAQS must reduce emissions to the level which reflects the LAER, as defined in section 171(3). The statute defines LAER as the rate of emissions based on the following, whichever is more stringent:

> (A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (B) the most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard.

A similar situation may arise under the prevention-of-significant-deterioration-of-air-quality provisions of the Act. These provisions require that certain sources employ BACT as defined in section 169(3) for all pollutants regulated under the Act. BACT must be determined on a case-by-case basis, taking energy, environmental and economic impacts, and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all cases, SIP's approved or promulgated under section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must, in some cases, require greater emission reduction than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

Under EPA's sunset policy for reporting requirements in regulations, the reporting requirements in this regulation will automatically expire 5 years from the date of promulgation unless EPA takes affirmative action to extend them.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance under section 111(b) of the Act. An economic impact assessment was prepared for the proposed regulations and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to ensure that the proposed standards would represent the best system of emission reduction considering costs. The economic impact assessment is included in the Background Information Document.

Dated: September 27, 1979.

Douglas M. Costle,

Administrator.

This proposed amendment to Part 60 of Chapter I, Title 40 of the Code of Federal Regulations would—

1. Add a definition of the term "volatile organic compound" to § 60.2 of Subpart A—General Provisions as follows:

§ 60.2 Definitions.

* * * * *

(dd) "Volatile Organic Compound" means any organic compound which participates in atmospheric photochemical reaction or is measured by the applicable reference methods specified under any subpart.

2. Add Subpart MM as follows:

Subpart MM—Standards of Performance for Automobile and Light-Duty Truck Surface Coating Operations

Authority: Secs. 111 and 301(a) of the Clean Air Act, as amended, [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart MM—Standards of Performance for Automobile and Light-Duty Truck Surface Coating Operations

§ 60.390 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to the following affected facilities in an automobile or light-duty truck surface coating line: each prime coat operation, each guide coat operation, and each topcoat operation.

(b) The provisions of this subpart apply to any affected facility identified in paragraph (a) of this section that begins construction or modification after ——— (date of publication in the **Federal Register**).

§ 60.391 Definitions.

All terms used in this subpart that are not defined below have the meaning given to them in the Act and in Subpart A of this part.

(a) "Automobile" means a motor vehicle capable of carrying no more than 12 passengers.

(b) "Automobile and light-duty truck body" means the body section rearward of the windshield and the front-end sheet metal or plastic exterior panel material forward of the windshield of an automobile or light-duty truck.

(c) "Bake oven" means a device which uses heat to dry or cure coatings.

(d) "Electrodeposition (EDP)" means a method of applying prime coat. The automobile or light-duty truck body is submerged in a tank filled with coating material, and an electrical field is used to deposit the material on the body.

(e) "Electrostatic spray application" means a spray application method that uses an electrical potential to increase the transfer efficiency of the coating solids. Electrostatic spray application can be used for prime coat, guide coat, or topcoat operations.

(f) "Flash-off area" means the structure on automobile and light-duty truck assembly lines between the coating application system (EDP tank or spray booth) and the bake oven.

(g) "Guide coat operation" means the guide coat spray booth, flash-off area and bake oven(s) which are used to apply and dry or cure a surface coating on automobile and light-duty truck bodies between the prime coat and topcoat operation.

(h) "Light-duty truck" means any motor vehicle rated at 3,850 kilograms (ca. 8,500 pounds) gross vehicle weight or less designed mainly to transport property.

(i) "Prime coat operation" means the prime coat application system (spray booth or dip tank), flash-off area, and bake oven(s) which are used to apply and dry or cure the initial coat on the surface of automobile or light-duty truck bodies.

(j) "Spray application" means a method of applying coatings by atomizing the coating material and directing this atomized spray toward the part to be coated. Spray applications can be used for prime coat, guide coat, and topcoat operations.

(k) "Spray booth" means a structure housing or manual spray application equipment where prime coat, guide coat, or topcoat is applied to automobile or light-duty truck bodies.

(l) "Surface coating operation" means any prime coat, guide coat, or topcoat operation on an automobile or light-duty truck surface coating line.

(m) "Topcoat operation" means the topcoat spray booth(s), flash-off area(s), and bake oven(s) which are used to apply and dry or cure the final coating(s) on automobile and light-duty truck bodies (i.e., those which give an automobile or light-duty truck body its color and surface appearance).

(n) "Transfer efficiency" means the fraction of the total applied coating solids which remains on the part.

(o) "Volatile organic compound" (VOC) means any organic compound which is measured by Method 24 (Candidate 1 or Candidate 2) and Method 25.

(p) "VOC emissions" means the mass of volatile organic compounds, expressed as kilograms of carbon per liter of applied coating solids, emitted from a surface coating operation.

(q) "VOC content" means the volatile organic compound content, in kilograms of carbon per liter of coating solids, of a coating material used in spray applications or coating make-up stream to an EDP tank.

§ 60.392 Standards for volatile organic compounds.

After the performance test required by § 60.8 has been completed, no owner or operator subject to the provisions of this subpart shall discharge or cause of the discharge into the atmosphere of VOC emissions which exceed the following limits:

(a) 0.10 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each prime coat operation.

(b) 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each guide coat operation.

(c) 0.84 kilogram of VOC (measured as mass of carbon) per liter of applied coating solids from each topcoat operation.

§ 60.393 Monitoring of operations.

(a) Any owner or operator subject to the provisions of this subpart shall—(1) Install, calibrate, operate, and maintain a monitoring device which records the combustion temperature of any effluent gases which are emitted from any surface coating operation and which are incinerated to comply with § 60.392. The manufacturer must certify that the monitoring device is accurate to within ±2°C (±3.6°F).

(2) Determine the weighted average VOC content of the coating materials used in any EDP prime coat operation whenever a change occurs in the composition of any of these coating materials. The owner or operator shall compute the weighted average by the following equation:

$$C = \frac{\sum_{i=1}^{n} CS_i \times VOLS_i \times SC_i}{\sum_{i=1}^{n} VOLS_i \times SC_i}$$

where:

C = the weighted averaged VOC content of all the coating materials used in an EDP system.

CS_i = the VOC content of the material in each coating makeup stream.

$VOLS_i$ = the volume (cubic meters) of each makeup stream added to the EDP tank during the previous month.

SC_i = the solid content of the material in each coating makeup stream expressed as a volume fraction.

n = the number of makeup streams.

(3) Determine the average VOC content of the coating materials in any surface coating operation which uses spray application whenever a change occurs in the composition of any of these coating materials. The owner or operator shall determine and record the arithmetic average of the VOC content of all coating materials in a coating operation which uses more than one coating material.

(b) Any owner or operator subject to the provisions of this subpart shall report for each calendar quarter all measurement results as follows:

(1) Where compliance with § 60.392 is achieved without the use of add-on control devices, any month during which—

(i) The weighted average VOC content of the makeup materials used in any prime coat operation employing EDP exceeds the most recent value which demonstrated compliance with § 60.392(a) by the performance test required in § 60.8.

(ii) The arithmetic average VOC content of the coating materials used in any surface coating operation employing spray application exceeds the most recent value which demonstrated compliance with § 60.392 by the performance test required in § 60.8.

(2) Where compliance with § 60.392 is achieved by the use of incineration, all periods in excess of 5 minutes during which the temperature in any incinerator used to control the emission from a surface coating operation remains below the most recent level which demonstrated compliance with § 60.392 by the performance tests required in § 60.8. The report required under § 60.7(c) shall identify each such occurrence and its duration.

(3) The reporting requirements in this regulation will automatically expire five years from the date of promulgation unless EPA takes affirmative action to extend them.

§ 60.394 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in § 60.8(b), shall be used to determine compliance with § 60.392 as follows:

(1) The owner or operator shall use Reference Method 24 (Candidate 1 or Candidate 2) to measure the VOC content of every coating or makeup material used in each surface coating operation of an automobile or light-duty truck surface coating line. The coating sample shall be a 1 liter sample taken at a point where the sample will be representative of the coating material as applied to the vehicle surface. The 1 liter sample shall be divided into three aliquots for triplicate determinations by Method 24 (Candidate 1 or Candidate 2).

(2) The owner or operator shall compute the arithmetic average VOC content of all coating materials used in each surface coating operation that uses spray application.

(3) The owner or operator shall use the calculation procedures given in § 60.393(a)(2) to compute the weighted average VOC content of all makeup materials added to an EDP tank during a selected one month period for each prime coat operation that uses EDP.

(4) The owner or operator shall determine the VOC emissions by the equation:

$$E = \frac{C}{TE}$$

where:

E = the VOC emissions.

C = the average VOC content of all the coating or makeup materials used in that operation. The owner or operator shall use an arithmetic average for systems using spray application and a weighted average for systems using EDP.

TE = the appropriate transfer efficiency as determined in paragraph (a)(5) of this section.

(5) The owner or operator shall select the appropriate transfer efficiency from the following table for each surface coating operation.

Application method	Transfer efficiency (TE)
Air Atomized Spray	0.40
Manual Electrostatic Spray	0.75
Automatic Electrostatic Spray	0.95
Electrodeposition	1.00

If the owner or operator can justify to the Administrator's satisfaction that other values for transfer efficiencies are appropriate, the Administrator will approve their use on a case-by-case basis. Where more than one application method is used on an individual surface coating operation, the owner or operator shall perform an analysis to determine the relative volume of solids coating materials applied by each method. The owner or operator shall use these relative volumes of solids to compute a weighted average transfer efficiency for the operation. The Administrator will review and approve this analysis on a case-by-case basis.

(b) For each surface coating operation which cannot achieve compliance with § 60.392 without the use of add-on control devices, the owner or operator shall use the following procedures to determine that the emission reduction efficiency of the control device(s) is sufficient to achieve compliance with § 60.392:

(1) The owner or operator shall compute the emission reduction efficiency required for each surface coating operation by the following equation:

$$ER = \frac{E - EL}{E} \times 100$$

where:

ER = the required emission reduction efficiency (in percent) for the applicable surface coating operation to achieve compliance with § 60.392.

E = the VOC emissions from the applicable surface coating operation.

EL = the numerical VOC emission limit in § 60.392 for the applicable surface coating operation.

(2) The owner or operator shall determine the emission reduction efficiency achieved by the control device(s) on each applicable surface coating operation as follows:

(i) The owner or operator shall use Reference Method 25 to determine the

VOC concentration in the effluent gas before and after the emission control device for each stack that is equipped with an emission control device. The owner or operator shall use Reference Method 2 to determine the volumetric flowrate of the effluent gas before and after the emission control device on each stack. The Administrator will approve testing of representative stacks, on a case-by-case basis, if the owner or operator can show to the Administrator's satisfaction that testing of representative stacks yields results comparable to those that would be obtained by testing all stacks.

(ii) For Method 25, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be at least 0.003 dscm (0.106 dscf) except that shorter sampling times or smaller volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(iii) The owner or operator shall determine the efficiency of each emission control device by the following equation:

$$EFF = \frac{(CB \times VOLB) - (CA \times VOLA)}{(CB \times VOLB)} \times 100$$

where:

EFF = the emission control device efficiency, in percent.

CB = the concentration of VOC in the effluent gas before the emission control device, in parts per million by volume.

CA = the concentration of VOC in the effluent gas after the emission control device, in parts per million by volume.

VOLA = the volumetric flow rate of the effluent gas after the emission control device, in dry standard cubic meters per second.

VOLB = the volumetric flow rate of the effluent gas before the emission control device, in dry standard cubic meters per second.

If an emission control device controls the emissions from more than one stack, the owner or operator shall measure CB and VOLB at a location between the manifold that receives all the exhausts from the applicable surface coating operation and the control device. If a manifold is not used, the product CB × VOLB shall be replaced by the sum of the individual products for each stack on the applicable surface coating operation controlled by this device.

(iv) The owner or operator shall determine the fraction of the total VOC discharged from an applicable surface coating operation which enters each emission control device on that operation by the following equation:

$$F_i = \frac{CB_i \times VOLB_i}{\sum_{k=1}^{n} (CB_k \times VOLB_k)}$$

where:

F_i = the fraction of the total VOC discharged from the applicable surface coating operation which enters the emission control device.

CB_i = the value of CB for stack (k) on the applicable surface coating operation.

CB_k = the value of CB for each stack (k) on the applicable surface coating operation.

$VOLB_i$ = the value of VOLB for each emission control device (i).

$VOLB_k$ = the value of VOLB for each stack (k) on the applicable surface coating operation.

n = the number of stacks on the applicable surface coating operation.

The owner or operator shall use the procedures contained in clause (ii) of this subparagraph for any emission control device (i) that controls the emissions from more than one stack.

(v) The owner or operator shall determine the emission reduction efficiency achieved by the control device(s) on the applicable surface coating operation using the equation:

$$EA = \sum_{i=1}^{m} (F_i \times EFF_i)$$

where:

EA = the emission reduction efficiency achieved, in percent.

EFF_i = the emission reduction efficiency (in percent) of each control device on the applicable surface coating operation.

m = the number of control devices on the applicable surface coating operation.

(3) If EA is greater than or equal to ER, the applicable surface coating operation will be in compliance with § 60.392.

§ 60.395 Modifications.

(a) The following physical or operational changes are not, by themselves, considered modifications of existing facilities:

(1) Changes as a result of model year changeovers or switches to larger cars.

(2) Changes in the application of the coatings to increase paint film thickness.

Appendix A—Reference Methods

3. Method 24 (Candidate 1), Method 24 (Candidate 2), and Method 25 are added to Appendix A as follows:

* * * * *

Method 24 (Candidate 1)—Determination of Volatile Content (as Carbon) of Paint, Varnish, Lacquer, or Related Products

1. Applicability and Principle

1.1 *Applicability.* This method is applicable for the determination of volatile content (as carbon) of paint, varnish, lacquer, and related products listed in Section 2.

1.2 *Principle.* The weight of volatile carbon per unit volume of solids is calculated for paint, varnish, lacquer, or related surface coating after using standard methods to determine the volatile matter content, density of the coating, density of the solvent, and using the oxidation-nondispersive infrared (NDIR) analysis for the carbon content.

2. Classification of Surface Coating

For the purpose of this method, the applicable surface coatings are divided into two classes. They are:

2.1 *Class I: General Solvent-Type Paints and Water Thinned Paints.* This class includes white linseed oil outside paint, white soya and phthalic alkyd enamel, white linseed o-phthalic alkyd enamel, red lead primer, zinc chromate primer, flat white inside enamel, white epoxy enamel, white vinyl toluene, modified alkyd, white amino modified baking enamel, and other solvent-type paints not included in class II. It also includes emulsion or latex paints and colored enamels.

2.2 *Class II: Varnishes and Lacquers.* This class includes clear and pigmented lacquers and varnishes.

3. Applicable Standard Methods

Use the apparatus, reagents, and procedures specified in the standard methods below:

3.1 *ASTM D 1644-59 Method A:* Standard Methods of test for Non-volatile Contents of Varnishes. Do not use Method B.

3.2 *ASTM D 1475-60.* Standard Method of Test for Density of Paint, Lacquer, and Related Products.

3.3 *ASTM D 2369-73:* Standard Method of Test for Volatile Content of Paints.

3.4 *ASTM D 3272-76:* Standard Recommended Practice for Vacuum Distillation of Solvents from Solvent-Base Paints for Analysis.

4. Apparatus (Oxidation/NDIR Procedure)

4.1 *Electric Furnace.* Capable of maintaining a temperature of 800±50° C.

4.2 *Combustion Chamber.* Stainless steel tubing, 13 mm (½ in.) internal diameter and 46 cm (18 in.) in length. Pack the tube loosely with 3 mm (⅛ in.) alumina pellets coated with 5 percent palladium. Place plugs of stainless steel wool at either end. Other catalytic systems which can demonstrate 95 percent efficiency as described in Section 6.5.4 are considered equivalent.

4.3 *Septum.* Teflon [1]-coated rubber septum.

4.4 *Condenser.* Ice bath condenser.

4.5 *Analyzer.* Nondispersive infrared analyzer (NDIR) to measure CO_2 **TO WITHIN ◊5 PERCENT OF THE CALIBRATION GAS CONCENTRATION.**

4.6 *Recorder.* Capable of matching the output of the NDIR.

4.7 *Collection Tank.* A collection tank of at least 6 liters in volume. See procedure in Section 6.5.1 for calibrating the volume of the tank. The tank should be capable of

[1] Mention of trade names or specific products does not constitute endorsement by the Environmental Protection Agency.

withstanding a pressure of 2000 mm (80 in.) Hg (gauge).

4.8 Pressure Gauge for Collection Tank. Capable of measuring positive pressure to 1100 mm (42 in.) Hg and vacuum pressure to 700±5 mm (28±0.25 in.) Hg.

4.9 Vacuum Pump. Capable of evacuating the collection tank to an absolute pressure of 51 mm (2 in.) Hg.

4.10 Analytical Balance. To measure to within ±0.5 mg.

4.11 Syringes. 100±1.0 μl, 500±1.0 μl, and 1000±5 μl syringe, with needles long enough to inject sample directly into the carrier gas stream.

4.12 Mixer. Vortex-mixer to ensure homogeneous mixing of solvent.

4.13 Flow Regulators. Rotameters, or equivalent, to measure to 500 cc/min in flow-rate.

4.14 Temperature Gauge. A thermometer graduated in 0.1° C, with range from 0° C to 100° C.

4.15 Tank Calibration Equipment. A balance to weigh collection tank to ±30 g or a graduated glass cylinder to measure tank volume within ±30 ml.

5. Reagents (Oxidation/NDIR Procedure)

5.1 Calibration Gases.

5.1.1 Zero Gas. Nitrogen.

5.1.2 CO_2 Gas. A range of concentration to allow at least a 3-point calibration of each measuring range of the instrument.

5.1.3 Carrier Gas. Air containing less than 1 ppm hydrocarbon as carbon, as certified by the manufacturer.

5.2 Catalyst. Alumina (3 mm pellets) coated with 5 percent palladium, or equivalent (commercially available).

5.3 Acetone. Reagent grade.

5.4 Nitric Acid Solution. Dilute 70 percent nitric acid 1:1 by volume with distilled water.

5.5 1-Butanol. Ninety-nine molecular percent pure.

5.6 Methane Gas. 0.5 percent methane in air.

6. Procedure

6.1 Classification of Samples. Assign the coating to one of the two classes discussed in Section 2 above. Assign any coating not clearly belonging to Class II to Class I.

6.2 Volatile Content. Use one of the following methods to determine the volatile content according to the class of coating.

6.2.1 Class I. Use the Procedure in ASTM D 2369–73. Record the following information:

W_1 = Weight of dish and sample, g.

W_2 = Weight of dish and sample after heating, g.

S = Sample weight, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction of volatile matter W for each analysis as follows:

$$W = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction $\bar{W}$ of the three determinations.

6.2.2 Class II. Use the procedure in ASTM D 1644–59 Method A; record the following information:

A = Weight of dish, g.

B = Weight of sample used, g.

C = Weight of dish and sample after heating, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction W of volatile content for each analysis as follows:

$$W = \frac{(A + B - C)}{B}$$

Report the arithmetic average weight fraction $\bar{W}$ of three determinations.

6.3 Coating Density. Determine the density D_m (in g/cm³) of the paint, varnish, lacquer, or related product of either class according to the procedure outlined in ASTM D 1475–60. Make a total of three determinations for each coating. Report the density $\bar{D}_m$ as the arithmetic average of the three determinations.

6.4 Solvent Density.

6.4.1 Perform the solvent extraction according to the procedure outlined in ASTM D 3272–76. For aqueous paint, use a collection-tube in an ice-bath prior to the collection-tube in the acetone and dry-ice mixture to prevent water from freezing in the collection-tube. Combine the contents of both tubes before analysis. If excessive foaming occurs during distillation, discard the sample, and repeat with a new sample treated with an anti-foam spray (e.g. Dow Corning's "Anti-foam A Spray) before distillation. Anti-foam spray must be nonorganic and nonflammable. Use spray sparingly.

6.4.2 Determine the density D_s (in g/cm³) of the solvent according to the procedure outlined in ASTM D 1475–60. Make a total of three determinations for the solvent, and report the average density $\bar{D}_s$ as the arithmetic average of the three determinations.

6.5 Carbon Content of the Solvent. Analyze the solvent within 24 hours after distillation; keep it under refrigeration when not in use. To determine the carbon content, follow the procedure below:

6.5.1 Clean and calibrate the collection tank as follows: Rinse the inside of the tank once with acetone, twice with tap water, thrice with the nitric acid solution, and twice with tap water. Weigh the tank when empty and when full of water. Measure the temperature of the water, and calculate the volume as follows:

$$V = \frac{W_f - W_e}{D_t}$$

Where:

t = Temperature of the water, °C (°F).

V = Volume of the tank, ml.

W_e = Weight of the empty tank, g.

W_f = Weight of the full tank, g.

D_t = Density of water at temperature t, g/ml.

Alternatively, measure the volume of water necessary to fill the tank. The volume of the tank connections and pressure gauge are negligible for a tank volume of at least 6 liters.

6.5.2 Calibrate the NDIR according to the manufacturer's instruction. Use at least a 3-point calibration. Introduce the CO_2 calibration gas through the analysis line.

6.5.3 Assemble the oxidation system as shown in Figure 1. Heat the catalyst until the temperature reaches equilibrium at 800 ±50° C. Add ice to the condenser and remove excess water to maintain the temperature at 0° C.

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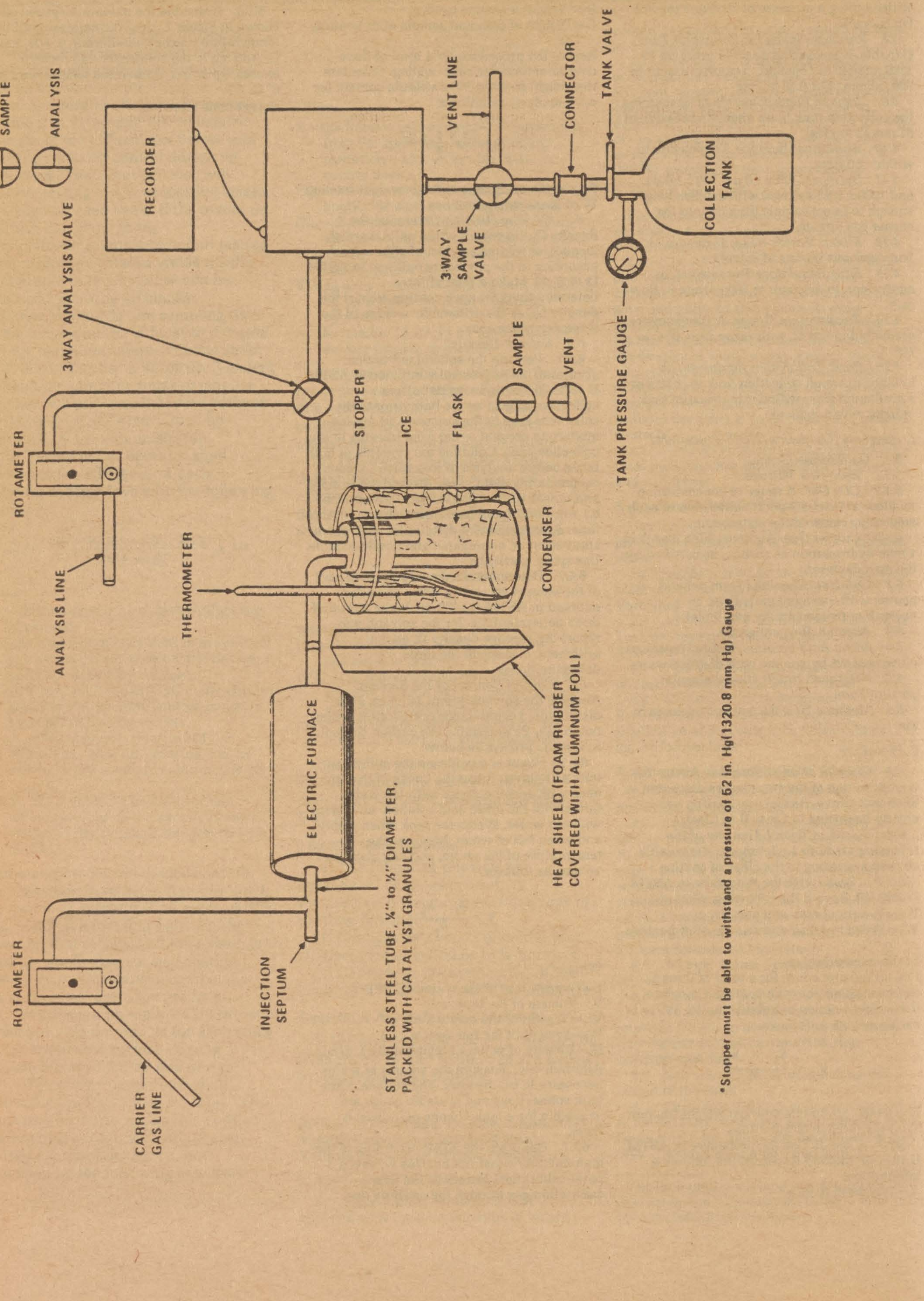
FIGURE 1


SAMPLE
ANALYSIS
3 WAY ANALYSIS VALVE
RECORDER
ROTAMETER
ANALYSIS LINE
THERMOMETER
ROTAMETER
CARRIER GAS LINE
INJECTION SEPTUM
ELECTRIC FURNACE
STAINLESS STEEL TUBE, ¼" to ½" DIAMETER, PACKED WITH CATALYST GRANULES
STOPPER*
ICE
FLASK
CONDENSER
HEAT SHIELD (FOAM RUBBER COVERED WITH ALUMINUM FOIL)
VENT LINE
3-WAY SAMPLE VALVE
SAMPLE
VENT
CONNECTOR
TANK VALVE
COLLECTION TANK
TANK PRESSURE GAUGE
*Stopper must be able to withstand a pressure of 52 in. Hg(1320.8 mm Hg) Gauge

6.5.4 Determination of Conversion Efficiency. Pass 0.5 percent methane gas in air through carrier gas line; 0.5 percent CO_2 should be generated within ±5 percent error. Using a 100 μl sample of l-butanol, follow the procedure in 6.5.5 to 6.5.13. Calculate the theoretical CO_2 volume percent as in Section 7.3. This value should equal the value as measured by the NDIR, within ±5 percent error. If conversion efficiency is 100 ±5 percent, analyze the solvent extracted from the paint according to procedure in Sections 6.5.5 to 6.5.14.

6.5.5 Purge the collection tank twice with N_2, then evacuate the tank to at least 50.8 mm (2 in.) Hg absolute pressure. Connect the cylinder to the collection line.

6.5.6 Mix the solvent sample thoroughly on a vortex-mixer. Then, draw a sample (0.100 to 0.300 ml) into the syringe. Record the volume of sample used.

6.5.7 Turn analysis valve to "sample" position, and turn the sample valve to "vent" position. Then turn on the carrier gas at a rate of 500 cc/min to flush the system for 2 minutes.

6.5.8 With gas flowing at 500 cc/min (maintain this rate throughout the test procedure), turn sample valve to "sample" position. Open the tank valve and inject the sample into the gas stream through the injection septum. Continue to draw the sample into the tank until the NDIR reads zero. (Note.— On replicate samples, a decrease in peak value indicates that the catalyst or sample has deteriorated, assuming that other factors, such as leaks, cell contamination, mechanical defects of the instruments, etc., have not occurred.)

6.5.9 At completion of collection, close the tank valve, and turn sample valve to "vent" position. Let the carrier gas flush the system for 2 minutes, then turn off the carrier gas.

6.5.10 Disconnect the tank and pressurize it with N_2 to about 1016 mm (40 in.) Hg gauge pressure. Record the final tank pressure after pressurization, the atmospheric pressure, and the room temperature.

6.5.11 Connect the tank to the analysis line and turn the analysis valve to "analysis" position.

6.5.12 Pass the CO_2 sample gas at the same rate as the calibration gas. Keep the rate constant by adjusting the rotameter as tank pressure falls.

6.5.13 Record the CO_2 concentration when the peak value is reached. This peak value will remain constant as long as the sample gas continues to flow at a constant rate.

6.5.14 Repeat steps 6.5.5 through 6.5.13 until three consecutive results are obtained which differ from one another in value by no more than ±5 percent. At the end of the third test, check the catalyst function by passing the collected sample gas through the catalyst and into the NDIR. No increase in concentration value should occur. If the concentration is higher, invalidate the test series, replace the catalyst and repeat the test.

6.5.15 Report the results as an arithmetic average of the three determinations.

7. Calculations. Carry out the calculations, retaining at least one extra decimal figure beyond that of the acquired data. Round off figures after decimal calculation.

7.1 Nomenclature.

C_c=Volatile matter content as carbon per unit volume of paint solids, g/l (lb/gal).
D_b=Density of l-Butanol, g/cm³.
D_m=Average coating density, g/cm³ (See Section 6.3).
D_s=Average solvent density, g/cm³ (See Section 6.4).
L_b=Volume of l-Butanol used in the test, cm³.
L_s=Volume of paint solvent used in the test, cm³.
74.12=Molecular weight of l-Butanol.
M_c=Mass of carbon, g.
4=Number of carbon atoms in l-Butanol.
P_{std}=Absolute standard pressure, 760 mm Hg (29.92 in. Hg).
P_f=Absolute final tank pressure after pressurization, mm Hg (in. Hg).
T_{std}=Absolute standard temperature, 293° K (528° R).
T_t=Absolute tank temperature, °K (°R).
%Solv.=Volume percent of solvent in paint coating.
V_{CO_2}=Volume of CO_2 in liters, at standard temperature and pressure.
V_{gs}=Total gas volume, corrected to standard conditions, in liters.
V_{pc}=Volume percent of CO_2.
V_t=Volume of tank, liters.
W=Weight fraction of volatile matter content.

7.2 Total Gas Volume, Corrected to Standard Conditions.

$$V_{gs} = \frac{T_{std}}{P_{std}} \frac{P_f}{T_t} V_t = K_1 \frac{P_f}{T_t} V_t \qquad \text{Equation 1}$$

Where:
K_1=17.65 for English units.
K_1=0.3855 for Metric units.

7.3 Volume Percent of CO_2 From l-Butanol:

$$V_{pc} = \frac{1.298\, L_b\, D_b}{V_{gs}} \qquad \text{Equation 2}$$

7.4 Mass of Carbon

$$M_c = V_{pc}\, V_{gs}\, \frac{12.0}{24.056}\, \frac{1}{100} \qquad \text{Equation 3}$$

7.5 Percent Volume Solvent in Paint.

$$\%\text{Solv.} = \overline{W}\, \frac{\overline{D}_m}{\overline{D}_s} (100) \qquad \text{Equation 4}$$

7.6 Volatile Matter Content as Carbon.

$$C_c = K_2 \frac{M_c}{L_s}\, \frac{\%\text{Solv.}}{100 - \%\text{Solv.}} \qquad \text{Equation 5}$$

Where:
K_2=8.3445 for English units.
K_2=1000 for Metric units.

8. Bibliography.

8.1 Standard Methods of Test for Nonvolatile Content of Varnishes. In: 1974 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 1644–59. 1974. p. 285–286.

8.2 Standard Method of Test for Volatile Content of Paints. In: 1978 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 2369–73. 1978. p. 431–432.

8.3 Standard Method of Test for Density of Paint, Varnish, Lacquer, and Related Products. In: 1974 Book of ASTM Standards, Part 25. Philadelphia, Pennsylvania, ASTM Designation D 1476–60. 1974. p. 231–233.

8.4 Standard Recommended Practice for Vacuum Distillation of Solvents from Solvent-Base Paints for Analysis. In: 1978 Annual Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 3272076. 1978. p. 612–614.

8.5 Salo, Albert E., William L. Oaks, and Robert D. MacPhee. Total Combustion Analysis. Air Pollution Control District-County of Los Angeles. August 1974.

Method 24 (Candidate 2)—Determination of Volatile Organic Compound Content (as Mass) of Paint, Varnish, Lacquer, or Related Products

1. *Applicability and Principle.*

1.1 Applicability. This method applies to the determination of volatile organic compound content (as mass) of paint, varnish, lacquer, and related products listed in Section 2.

1.2 Principle. Standard methods are used to determine the volatile matter content, density of the coating, volume of solid, and water content of the paint, varnish, lacquer, and related surface coating. From this information, the mass of volatile organic compounds per unit volume of solids is calculated.

2. *Classification of Surface Coating.* For the purpose of this method, the applicable surface coatings are divided into three classes. They are:

2.1 Class I: General Solvent Reducible Paints. This class includes white linseed oil outside paint, white soya and phthalic alkyd enamel, white linseed o-phthalic alkyd enamel, red lead primer, zinc chromate primer, flat white inside enamel, white epoxy enamel, white vinyl toluene, modified alkyd, white amino modified baking enamel, and other solvent-type paints not included in Class II.

2.2 Class II: Varnishes and Lacquers. This class includes clear and pigmented lacquers and varnishes.

2.3 Class III. This class includes all water reducible paints.

3. *Applicable Standard Methods.* Use the apparatus, reagents, and procedures specified in the standard method below:

3.1 ASTM D 1644–75 Method A: Standard Method of Test for Non-volatile Contents of Varnishes. Do not use Method B.

3.2 ASTM D 1475–60. Standard Method of Test for Density of Paint, Lacquer, and Related Products.

3.3 ASTM D 2369–73. Standard Method of Test for Volatile Content of Paints.

3.4 ASTM D 2697–73. Standard Method of Test for Volume Non-volatile Matter in Clear or Pigmented Coatings.

3.5 ASTM D 3792. Standard Method of Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph.

3.6 ASTM Draft Method of Test for Water in Paint or Related Coatings by the Karl Fischer Titration Method.

4. *Procedure.*

4.1 Classification of Samples. Assign the coating to one of the three classes discussed in Section 2 above. Assign any coating not clearly belonging to Class II or III to Class I.

4.2 Non-Aqueous Volatile Content. Use one of the following methods to determine the non-aqueous volatile content according to the class of coating.

4.2.1 Class I. Use the procedure in ASTM D 2369-73; record the following information:

W_1 = Weight of dish and sample, g.
W_2 = Weight of dish and sample after heating g.
S = Sample of weight, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction of non-aqueous volatile matter W_v for each analysis as follows:

$$W_v = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction $\bar{W}_v$ of the three determinations.

4.2.2 Class II. Use the procedure in ASTM D 1644-75 Method A; record the following information:

A = Weight of dish, g.
B = Weight of sample used, g.
C = Weight of dish and sample after heating, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction W_v of non-aqueous volatile content for each analysis as follows:

$$W_v = \frac{(A + B - C)}{B}$$

Report the arithmetic average weight fraction $\bar{W}_v$ of the three determinations.

4.2.3 Class III.

4.2.3.1 Water Content. Determine the water content (in % H_2O) of the coating according to either "Provisional Method of Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph" or "Provisional Method of Test for Water in Paint or Related coatings by the Karl Fischer Titration Method." Repeat the procedure for a total of three determinations for each coating. Report the arithmetic average weight percent $\overline{\%\ H_2O}$ of the three determinations.

4.2.3.2 Volatile Content (Including Water). Use the procedure in ASTM D 2369-73; record the following information:

W_1 = Weight of dish and sample, g.
W_2 = Weight of dish and sample after heating, g.
S = Sample weight, g.

Repeat the procedure for a total of three determinations for each coating. Calculate the weight fraction of volatile matter as follows:

$$V = \frac{W_1 - W_2}{S}$$

Report the arithmetic average weight fraction $\bar{V}$ of the three determinations.

4.2.3.3 Non-Aqueous Volatile Matter. Calculate the average non-aqueous volatile matter $\bar{W}_v$ as follows:

$$\bar{W}_v = \bar{V} - \frac{\overline{\%\ H_2O}}{100}$$

4.3 Coating Density. Determine the density D_m (in g/cm³) of the paint, varnish, lacquer, or related product of any class according to the procedure outlined in ASTM D 1475-60. Make a total of three determinations for each coating. Report the density $\bar{D}_m$ as the arithmetic average of the three determinations.

4.4 Non-Volatile Content. Determine the volume fraction of the non-volatile matter of the coating of any class according to the procedure outlined in ASTM D 2697-73. Calculate the volume fraction P_n of non-volatile matter as follows:

$$P_n = \frac{\%\ \text{Volume Nonvolatile Matter}}{100}$$

Make a total of three determinations for each coating. Report the arithmetic average volume fraction $\bar{P}_n$ of the three determinations.

5. *Volatile Organic Compounds Content.* Calculate the volatile organic compound content C_m in terms of mass per volume of solids (g/liter) as follows:

$$C_m = \frac{\bar{W}_v\ \bar{D}_m}{\bar{P}_n}$$

To convert g/liter to lb/gal, multiply C_m by 8.3455×10^{-3}.

6. *Bibliography.*

6.1 Standard Methods of Test of Nonvolatile Content of Varnishes. In: 1974 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania. ASTM Designation D 1644-75. 1978. p. 288-289.

6.2 Standard Method of Test for Volatile Content of Paints. In: 1978 Book of ASTM Standards, Part 27. Philadelphia, Pennsylvania, ASTM Designation D 2369-73. 1978. p. 431-432.

6.3 Standard Method of Test for Density of Paint, Varnish, Lacquer, and Related Products. In: 1974 Book of ASTM Standards, Part 25. Philadelphia, Pennsylvania, ASTM Designation D 1476-60. 1974. p. 231-233.

6.4 Standard Method of Test for Water in Water Reducible Paint by Direct Injection into a Gas Chromatograph. Available from: Chairman, Committee D-1 on Paint and Related Coatings and Materials, American Society for Testing and Materials, 1916 Race St., Philadelphia, PA 19103. ASTM Designation D 3792.

6.5 Draft method of Test for Water in Paint or Related Coatings by the Karl Fischer Titration Method. Available from: Chairman, Committee D-1 on Paint and Related Coatings and Materials, American Society for Testing and Materials, 1916 Race St., Philadelphia, PA 19103.

Method 25—Determination of Total Gaseous Nonmethane Organic Emissions as Carbon: Manual Sampling and Analysis Procedure

1. Principle and Applicability.

1.1 Principle. An emission sample is anisokinetically drawn from the stack through a chilled condensate trap by means of an evacuated gas collection tank. Total gaseous nonmethane organics (TGNMO) are determined by combining the analytical results obtained from independent analyses of the condensate trap and evacuated tank fractions. After sampling is completed, the organic contents of the condensate trap are oxidized to carbon dioxide which is quantitatively collected in an evacuated vessel; a portion of the carbon dioxide is reduced to methane and measured by a flame ionization detector (FID). A portion of the sample collected in the gas sampling tank is injected into a gas chromatographic (GC) column to achieve separation of the nonmethane organics from carbon monoxide, carbon dioxide and methane; the nonmethane organics are oxidized to carbon dioxide, reduced to methane, and measured by a FID.

1.2 Applicability. This method is applicable to the measurement of total gaseous nonmethane organics in source emissions.

2. Apparatus.

2.1 General. TGNMO sampling equipment can be constructed by a laboratory from commercially available components and components fabricated in a machine shop. The primary components of the sampling system are a condensate trap, flow control system, and gas sampling tank (Figure 1). The analytical system consists of two major subsystems; an oxidation system for recovery of the sample from the condensate trap and a TGNMO analyzer. The TGNMO analyzer is a FID preceded by a reduction catalyst, oxidation catalyst, and GC column with backflush capability (Figures 2 and 3). The system for the removal and conditioning of the organics captured in the condensate trap consists of a heat source, oxidation catalyst, nondispersive infrared (NDIR) analyzer and an intermediate gas collection tank (Figure 4).

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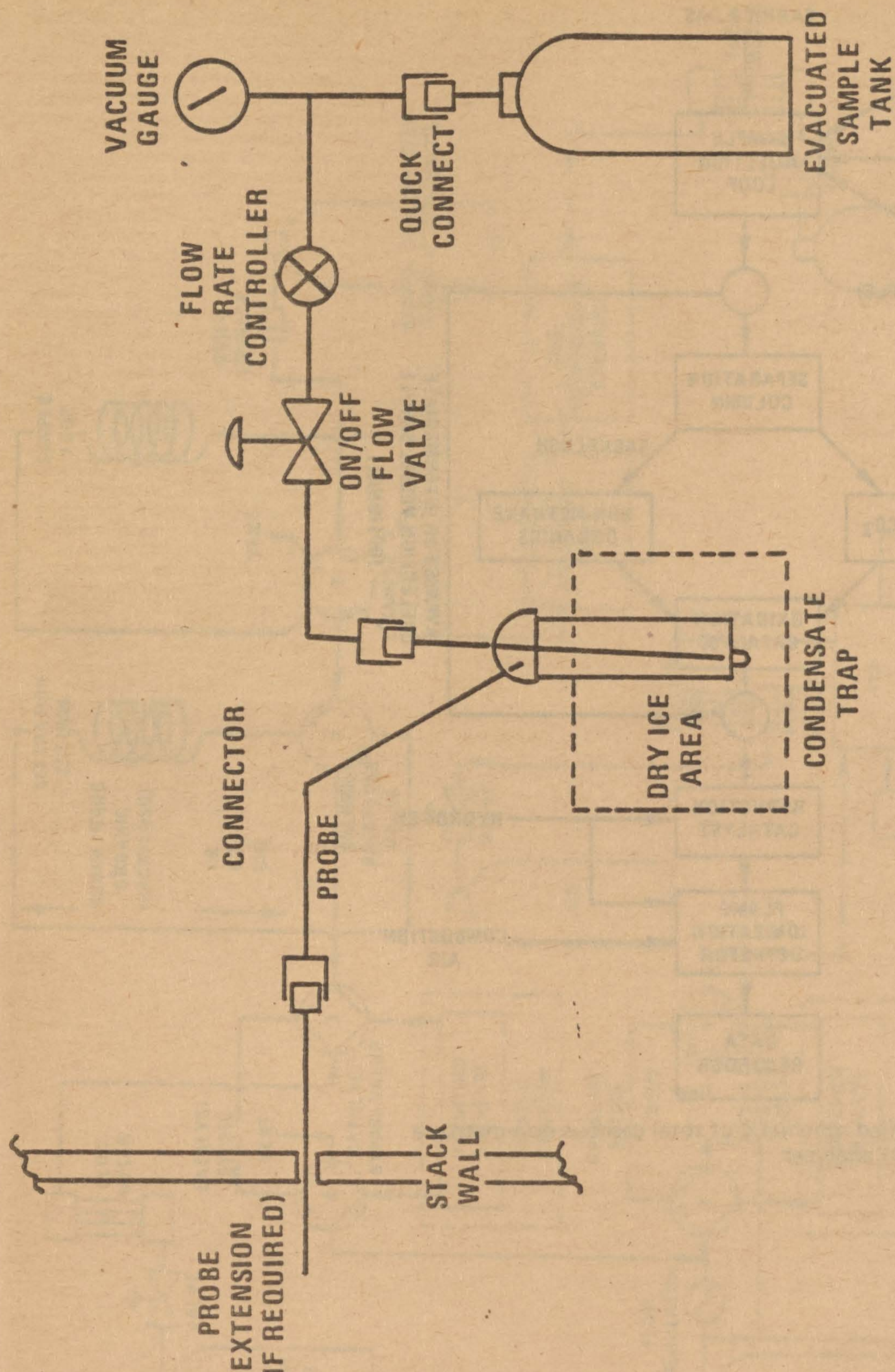

Figure 1. Sampling apparatus.

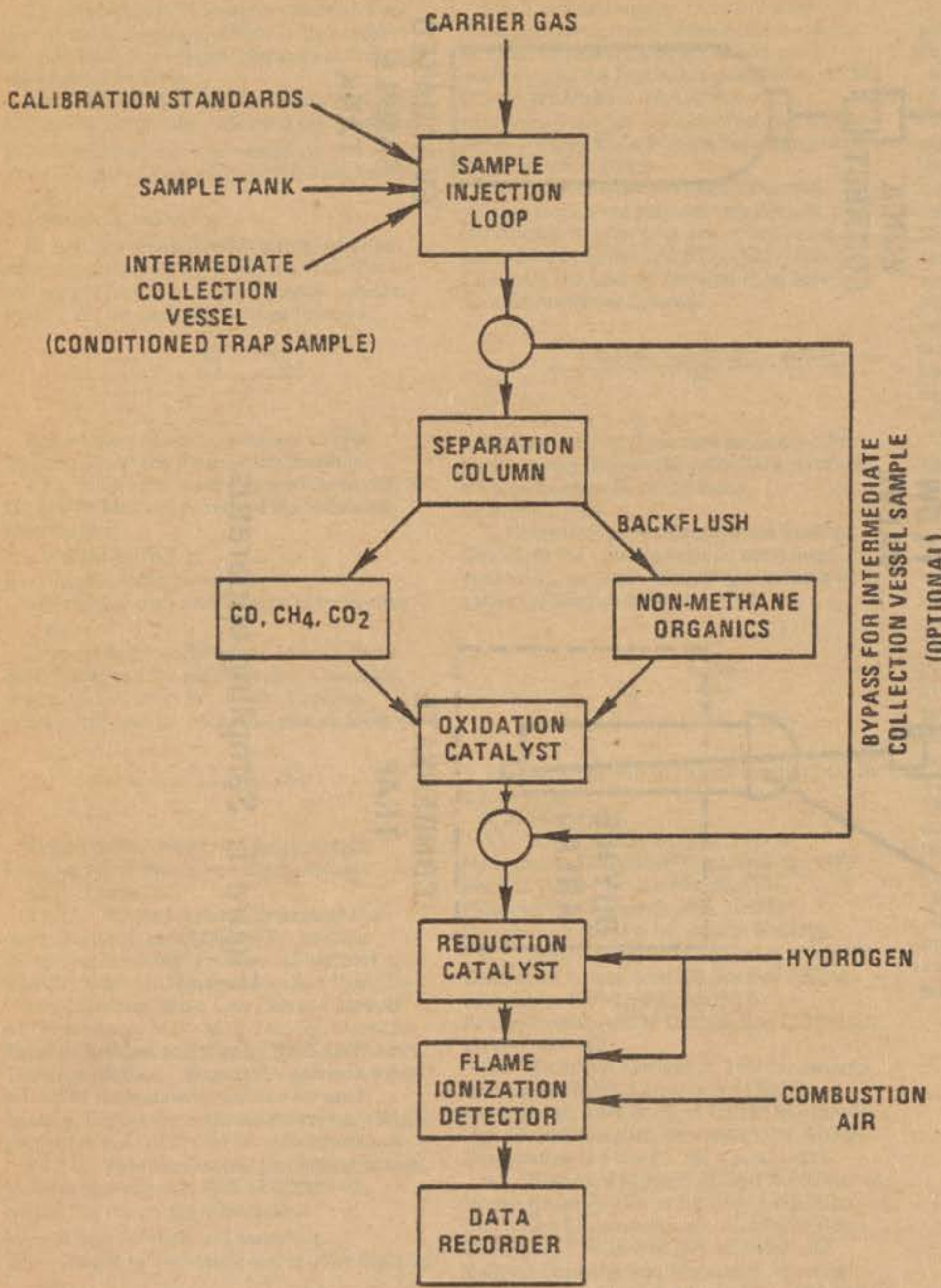

Figure 2. Simplified schematic of total gaseous non-methane organic (TGNMO) analyzer.

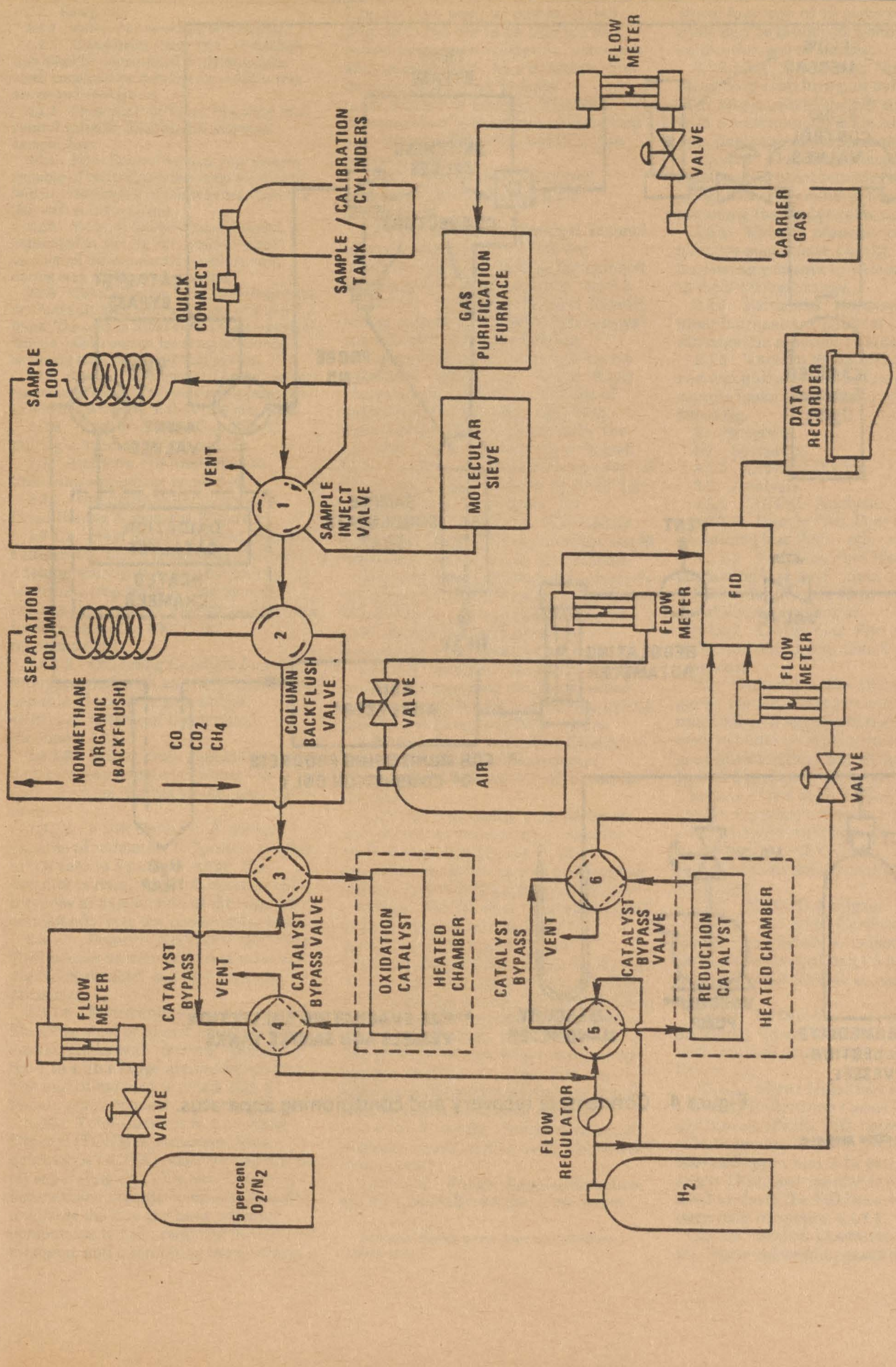

Figure 3. Total gaseous nonmethane organic (TGNMO) analyzer.

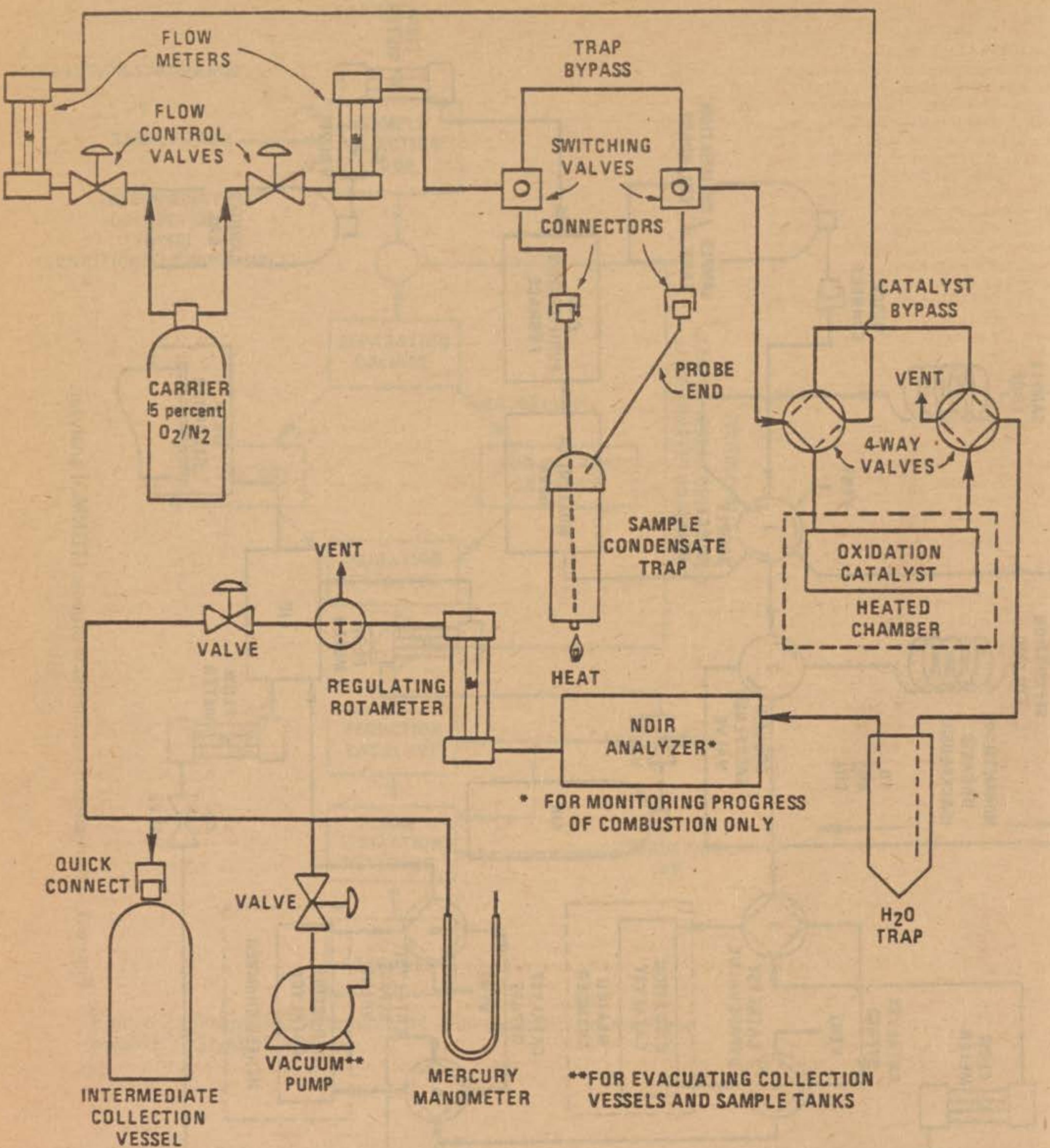

Figure 4. Condensate recovery and conditioning apparatus.

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2.2 Sampling.

2.2.1 Probe. ⅛" stainless steel tubing.

2.2.2 Condensate Trap. The condensate trap shall be constructed of 316 stainless steel; construction details of a suitable trap are shown in Figure 5.

2.2.3 Flow Shut-off Valve. Stainless steel control valve for starting and stopping sample flow.

2.2.4 Flow Control System. Any system capable of maintaining the sampling rate to within ±10 percent of the selected flow rate (50—100 cc/min. range).

2.2.5 Vacuum Gauge. Vacuum gauge calibrated in mm Hg. for monitoring the vacuum of the evacuated sampling tank during leak checks and sampling.

2.2.6 Gas Collection Tank. Stainless steel or aluminum tank with a volume of 4 to 8 liters. The tank is fitted with a stainless steel female quick connect for assembly to the sampling train and analytical system.

2.2.7 Mercury manometer. U-tube mercury manometer capable of measureing pressure to within 1.0 mm Hg in the 0/900 mm range.

2.2.8 Vacuum Pump. Capable of pulling a vacuum of 700 mm Hg.

2.3 Analysis. For analysis, the following equipment is needed.

2.3.1 Condensate Recovery and Conditioning Apparatus (Figure 4).

2.3.1.1 Heat Source. A heat source sufficient to heat the condensate trap to a temperature just below the point where the trap turns a "cherry red" color is required. An electric muffle-type furnace heated to 600° C is recommended.

2.3.1.2 Oxidizing Catalyst. Inconel tubing packed with an oxidizing catalyst capable of meeting the catalyst efficiency criteria of this method (Section 4.4.2).

2.3.1.3 Water Trap. Any leak proof moisture trap capable of removing moisture from the gas stream may be used.

2.3.1.4 NDIR Detector. A detector capable of indicating CO_2 concentration in the zero to 5 percent range. This detector is required for monitoring the progress of combustion of the organic compounds from the condensate trap.

2.3.1.5 Pressure Regulator. Stainless steel needle valve required to maintain the NDIR detector cell at a constant pressure.

2.3.1.6 Intermediate Collection Tank. Stainless steel or aluminum collection vessel. Tanks with nominal volumes in the 1 to 4 liter range are recommended. The end of the tank is fitted with a female quick connect.

2.3.2 Total Gaseous Nonmethane Organic (TGNMO) Analyzer. Semi-continuous GC/FID analyzer capable of: (1) separating CO, CO_2, and CH_4 from nonmethane organic compounds, and (2) oxidizing the non-methane organic compounds to CO_2, reducing the CO_2 to methane, and quantifying the methane. The analyzer shall be demonstrated prior to initial use to be capable of proper separation, oxidation, reduction, and measurement. As a minimum, this demonstration shall include measurement of a known TGNMO concentration present in a mixture that also contains CH_4, CO, and CO_2 (see paragraph 4.4.1).

2.3.2.1 The TGNMO analyzer consists of the following major components.

2.3.2.1.1 Oxidation Catalyst. Inconel tubing packed with an oxidation catalyst capable of meeting the catalyst efficiency criteria of paragraph 4.4.1.2.

2.3.2.1.2 Reduction Catalyst. Inconel tubing packed with a reduction catalyst capable of meeting the catalyst efficiency criteria of paragraph 4.4.1.3.

2.3.2.1.3 Separation Column. A gas chromatographic column capable of separating CO, CO_2, and CH_4 from nonmethane organic compounds. The specified column is as follows: ⅛ inch O.D. stainless steel packed with 3 feet of 10 percent methyl silicone, Sp 2100* (or equivalent) on Supelcoport* (or equivalent), 80/100 mesh, followed by 1.5 feet porapak Q* (or equivalent) 60/80 mesh. The inlet side is to the silicone.

Other columns may be used subject to the approval of the Administrator. In any event, proper separation shall be demonstrated according to the procedures of paragraph 4.4.1.4.

2.3.2.1.4 Sample Injection System. A gas chromatographic sample injection valve with sample loop sized to properly interface with the TGNMO system.

2.3.2.1.5 Flame Ionization Detector (FID). A flame ionization detector meeting the following specifications is required:

2.3.2.1.5.1 Linearity. A linearity of ±5 percent of the expected value for each full scale setting up to the maximum percent absolute (methane or carbon equivalent) calibration point is required. The FID shall be demonstrated prior to initial use to meet this specification through a 5-point (minimum) calibration. There shall be at least one calibration point in each of the following ranges: 5–10, 50–100, 500–1,000, 5,000–10,000, and 40,000–100,000 ppm (methane or carbon equivalent). Certification of such demonstration by the manufacturer is acceptable. An additional linearity performance check (see Section 4.4.1.1) must be made before each use (i.e., before each set of samples is analyzed or daily whichever occurs first).

2.3.2.1.5.2 Range. Signal attenuators shall be available so that a minimum signal response of 10 percent of full scale can be produced when analyzing calibration gas or sample.

*Mention of trade name does not constitute endorsement.

2.3.2.1.5.3 Sensitivity. The detector sensitivity shall be equal to or better than 2.0 percent of the full scale setting, with a minimum full scale setting of 10 ppm (methane or carbon equivalent).

2.3.2.1.6 Data Recording System. Analog strip chart recorder or digital integration system for permanently recording the analytical results.

2.3.3 Mercury Manometer. U-tube mercury manometer capable of measuring pressure to within 1.0 mm Hg in the 0–900 mm range.

2.3.4 Barometer. Mercury, aneroid, or other barometer capable of measuring atmospheric pressure to within 1 mm.

2.3.5 Vacuum Pump. Laboratory vacuum pump capable of evacuating the sample tanks to an absolute pressure of 5 mm Hg.

3. Reagents.

3.1 Sampling.

3.1.1 Crushed Dry Ice.

3.2 Analysis.

3.2.1 TGNMO Analyzer.

3.2.1.1 Carrier Gas. Pure helium, containing less than 1 ppm organics.

3.2.1.2 Fuel Gas. Pure Hydrogen, containing less than 1 ppm organics.

3.2.2 Condensate Recovery and Conditioning Apparatus.

3.2.2.1 Carrier Gas. Five percent O_2 in N_2, containing less than 1 ppm organics.

3.3 Calibration. For all calibration gases, the manufacturer must recommend a maximum shelf life for each cylinder so that the gas concentration does not change more than ±5 percent from its certified value. The date of gas cylinder preparation, certified organic concentration and recommended maximum shelf life must be affixed to each cylinder before shipment from the gas manufacturer to the buyer.

3.3.1 TGNMO Analyzer.

3.3.1.1 Oxidation Catalyst Efficiency Check. Gas mixture standard with nominal concentration of 5 percent methane and 5 percent oxygen in nitrogen.

3.3.1.2 Reducation Catalyst Efficiency Check. Gas mixture standard with nominal concentration of 5 percent CO_2 in air.

3.3.1.3 Flame Ionization Detector Linearity Calibration Gases (3). Gas mixture standards with known methane (CH_4) concentrations in the 5–10 ppm, 500–1,000 ppm, and 5–10 percent range, in air. These gas standards are to be used to check the FID linearity as described in Section 4.4.1.1.

3.3.1.4 System Operation Standards (2). These calibration gases are required to check the total system operation as specified in Section 4.4.1.4. Two gas mixtures are required:

3.3.1.4.1 Gas mixture standard containing (nominal) 50 ppm CO, 50 ppm CH_4, 2 percent CO_2, and 15 ppm C_3H_8, prepared in air.

3.3.1.4.2 Gas mixture standard containing (nominal) 50 ppm CO, 50 ppm CH_4, 2 percent CO_2, and 1,000 ppm C_3H_8, prepared in air.

3.3.2 Condensate Recovery and Conditioning Apparatus. The calibration gas specified in paragraph 3.3.1.1 is required for performing an oxidation catalyst check according to the procedure of paragraph 4.4.2.

4. *Procedure.*

4.1 Sampling.

4.1.1 Sample Tank Evacuation. Either in the laboratory or in the field, evacuate the sample tank to 5 mm Hg absolute pressure or less (measured by a mercury U-tube manometer). Record the temperature, barometric pressure, and tank vacuum as measured by the manometer.

4.1.2 Sample Tank Leak Check. Leak check the gas sample tank immediately after the tank is evacuated. Once the tank is evacuated, allow the tank to sit for 30 minutes. The tank is acceptable if no change in tank vacuum (measured by the mercury manometer) is noted.

4.1.3 Assembly. Just prior to assembly, use a mercury U-tube manometer to measure the tank vacuum. Record this vacuum (P_{ti}), the ambient temperature (T_{ti}), and the barometric pressure (P_{bi}) at this time. Assuring that the flow control valve is in the closed position, assemble the sampling system as shown in Figure 1. Immerse the condensate trap body in dry ice to within 1 or 2 inches of the point where the inlet tube joins the trap body.

4.1.4 Leak Check Procedures.

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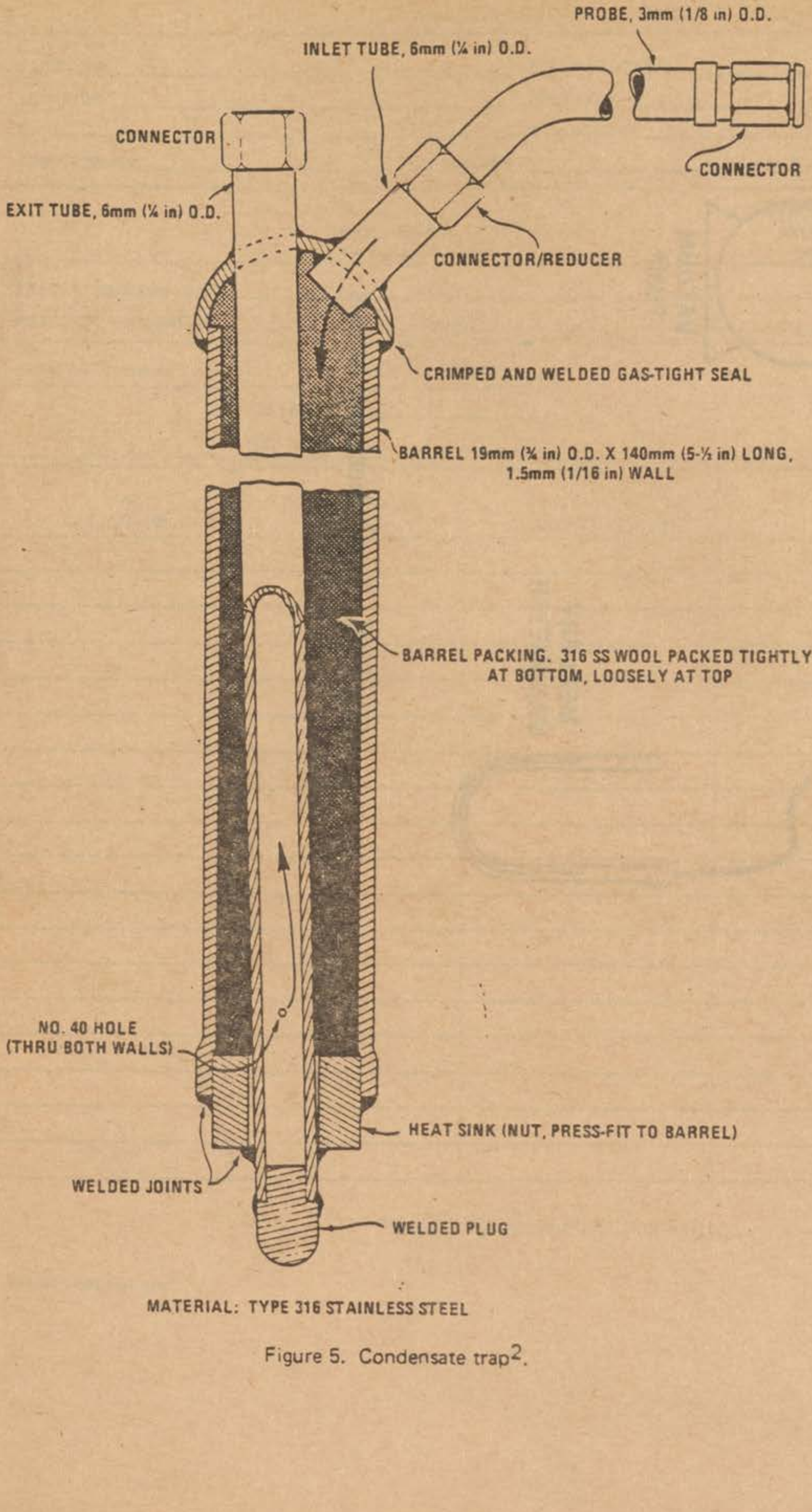

Figure 5. Condensate trap[2].

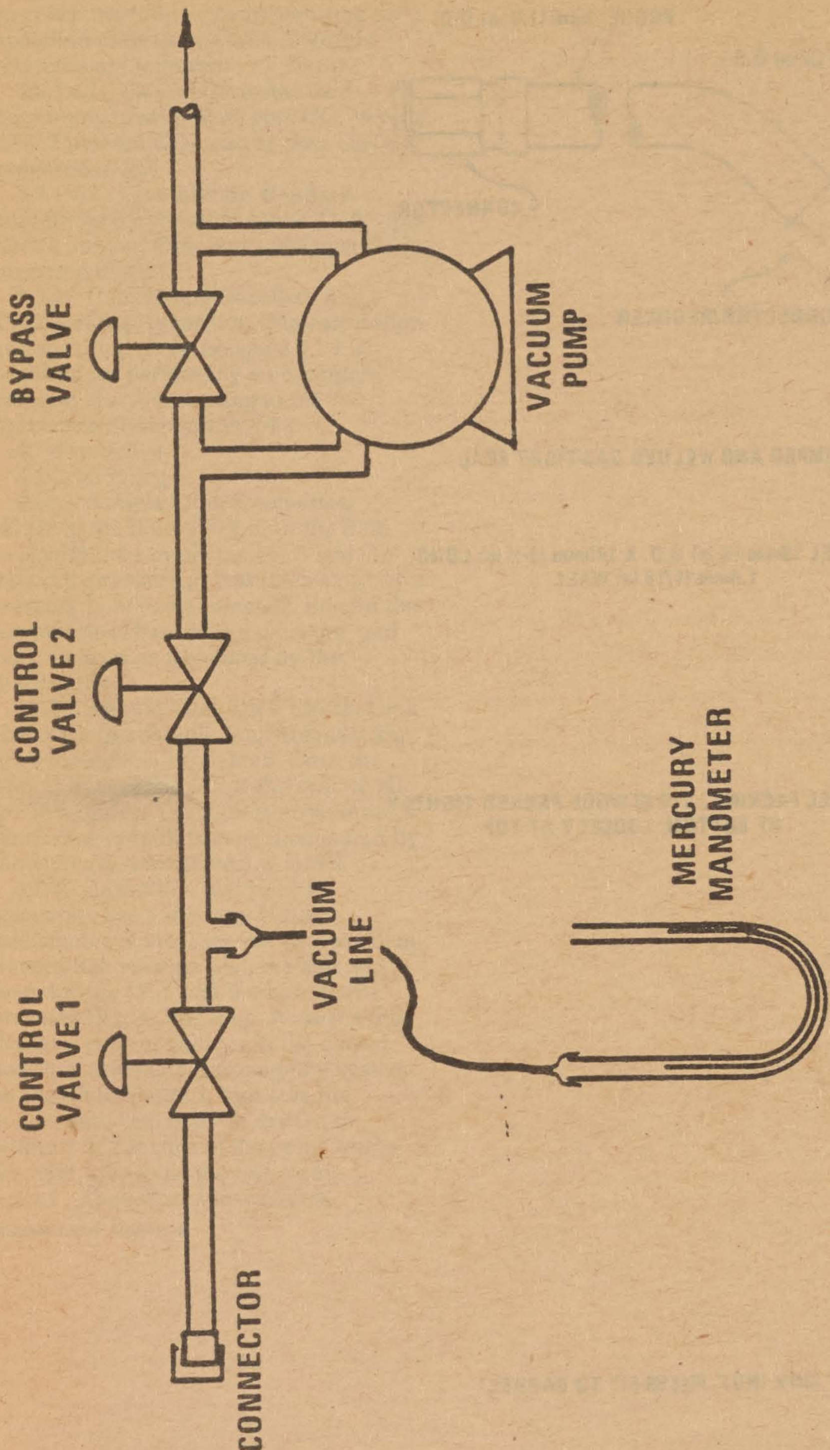

Figure 6. Leak check apparatus.

VOLATILE ORGANIC CARBON

FACILITY ______________ SAMPLE LOCATION ______________

LOCATION ______________ OPERATOR ______________

DATE ______________ RUN NUMBER ______________

TANK NUMBER ______________ TRAP NUMBER ______________ SAMPLE ID NUMBER ______________

TANK VACUUM, mm Hg		BAROMETRIC PRESSURE, mm Hg	AMBIENT TEMPERATURE, °C
PRETEST (MANOMETER) ______	(GAUGE) ______		
POST TEST (MANOMETER) ______	(GAUGE) ______		

LEAK RATE, mm Hg/5 min.:	TANK	TRAP HALF
PRETEST		
POST TEST		

TIME CLOCK/SAMPLE	GAUGE VACUUM, mm Hg	FLOWMETER SETTING	COMMENTS

Figure 7. Example Field Data Form.

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4.1.4.1 Pretest Leak Check. A pretest leak check is required. After the sampling train is assembled, record the tank vacuum as indicated by the vacuum gauge. Wait a minimum period of 15 minutes and recheck the indicated vacuum. If the vacuum has not changed, the portion of the sampling train behind the shut-off valve does not leak and is considered acceptable. To check the front portion of the sampling train, attach the leak check apparatus (Figure 6) to the probe tip. Evacuate the front half of the train (i.e., do not open the sampling train flow control valve) to a vacuum of at least 500 mm Hg. Close the shut-off valve on the leak check apparatus and record the vacuum indicated by the manometer on the data sheet (Figure 7). Allow the system to sit for 5 minutes and then recheck the vacuum. A change of less than 2 mm Hg for the 5-minute leak check period is acceptable. Record the front half leak rate (mm Hg/5-minute period) on the data form. When an acceptable leak rate has been obtained disconnect the leak check apparatus from the probe tip.

4.1.4.2 Post Test Leak Check. A leak check is mandatory at the conclusion of each test run. After sampling is completed, attach the U-tube manometer to the probe tip; minimize the amount of flexible line used. Open the sample train flow control valve for a period of 2 minutes or until the vacuum indicated on the manometer stabilizes, whichever occurs first; shut off the sample train flow control valve. Record the vacuums indicated on the manometer (front half) and on the tank vacuum gauge (back-half). After 5 minutes, recheck these vacuum readings. A leak rate of less than 2 mm Hg per 5-minute period is acceptable for the front half; the back half portion is acceptable if no visible change in the tank vacuum gauge occurs. Record the post test leak rate (mm Hg per 5 minutes), and then disconnect the manometer from the probe tip and seal the probe. If the sampling train does not pass the post test leak check, invalidate the run.

4.1.5 Sample Train Operation. Place the probe into the stack such that the probe is perpendicular to the direction of stack gas flow; locate the probe tip at a single preselected point. For stacks having a negative static pressure, assure that the sample port is sufficiently sealed to prevent air in-leakage around the probe. Check the dry ice level and add ice if necessary. Record the clock time and sample tank gauge vacuum. To begin sampling, open and adjust (if applicable) the flow control valve(s) of the flow control system utilized in the sampling train; maintain a constant flow rate (± 10 percent) throughout the duration of the sampling period. Record the gauge vacuum and flowmeter setting (if applicable) at 5-minute intervals. Select a total sample time greater than or equal to the minimum sampling time specified in the applicable subpart of the regulation; end the sampling when this time period is reached or when a constant flow rate can no longer be maintained. When the sampling is completed, close the gas sampling tank control valve. Record the final readings. Note: If the sampling had to be stopped before obtaining the minimum sampling time (specified in the applicable subpart) because a constant flow rate could not be maintained, proceed as follows: After removing the probe from the stack, remove the evacuated tank from the sampling train (without disconnecting other portions of the sampling train) and connect another evacuated tank to the sampling train. Prior to attaching the new tank to the sampling train, assure that the tank vacuum (measured on-site by the U-tube manometer) has been recorded on the data form and that the tank has been leak-checked (on-site). After the new tank is attached to the sample train, proceed with the sampling; after the required minimum sampling time has been exceeded, end the test.

4.2 Sample Recovery. After sampling is completed, remove the probe from the stack and seal the probe end. Conduct the post test leak check according to the procedures of paragraph 4.1.4.2. After the post test leak check has been conducted, disconnect the condensate trap at the flow metering system. Tightly seal the ends of the condensate trap; keep the trap packed in dry ice until analysis. Remove the flow metering system from the sample tank. Attach the U-tube manometer to the tank (keep length of flexible connecting line to a minimum) and record the final tank vacuum (P_t); record the tank temperature (T_t) and barometric pressure at this time. Disconnect the manometer from the tank. Assure that the test run number is properly identified on the condensate trap and evacuated tank(s).

4.3 Analysis.

4.3.1 Preparation.

4.3.1.1 TGNMO Analyzer. Set the carrier gas, air, and fuel flow rates and then begin heating the catalysts to their operating temperatures. Conduct the calibration linearity check required in paragraph 4.4.1.1 and the system operation check required in paragraph 4.4.1.4. Optional: Conduct the catalyst performance checks required in paragraphs 4.4.1.2 and 4.4.1.3 prior to analyzing the test samples.

4.3.1.2 Condensate Recovery and Conditioning Apparatus. Set the carrier gas flow rate and begin heating the catalyst to its operating temperature. Conduct the catalyst performance check required in paragraph 4.4.2 prior to oxidizing any samples.

4.3.2 Condensate Trap Carbon Dioxide Purge and Evacuated Sample Tank Pressurization. The first step in analysis is to purge the condensate trap of any CO_2 which it may contain and to simultaneously pressurize the gas sample tank. This is accomplished as follows: Obtain both the sample tank and condensate trap from the test run to be analyzed. Set up the condensate recovery and conditioning apparatus so that the carrier flow bypasses the condensate trap hook-up terminals, bypasses the oxidation catalyst, and is vented to the atmosphere. Next, attach the condensate trap to the apparatus and pack the trap in dry ice. Assure that the valve isolating the collection vessel connection from the atmospheric vent is closed and then attach the gas sample tank to the system as if it were the intermediate collection vessel. Record the tank vacuum on the laboratory data form. Assure that the NDIR analyzer indicates a zero output level and then switch the carrier flow through the condensate trap; immediately switch the carrier flow from vent to collect and open the valve to the tank. The condensate trap recovery and conditioning apparatus should now be set up as indicated in Figure 8. Monitor the NDIR; when CO_2 is no longer being passed through the system, switch the carrier flow so that it once again bypasses the condensate trap. Continue in this manner until the gas sample tank is pressurized to a nominal gauge pressure of 800 mm mercury. At this time, isolate the tank, vent the carrier flow, and record the sample tank pressure (P_{tf}), barometric pressure (P_{bf}), and ambient temperature (T_{tf}). Remove the gas sample tank from the system.

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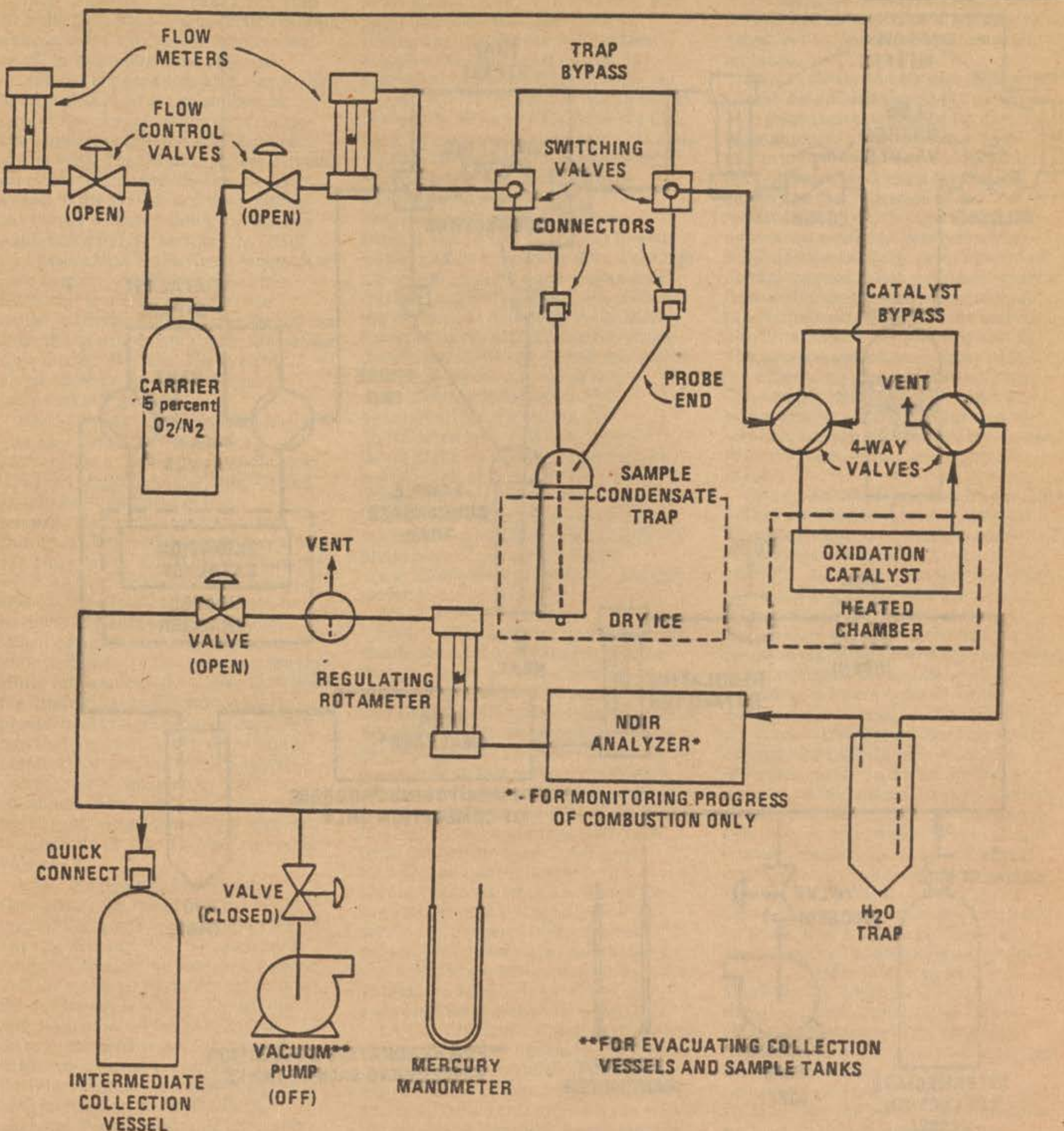

Figure 8. Condensate recovery and conditioning apparatus, carbon dioxide purge.

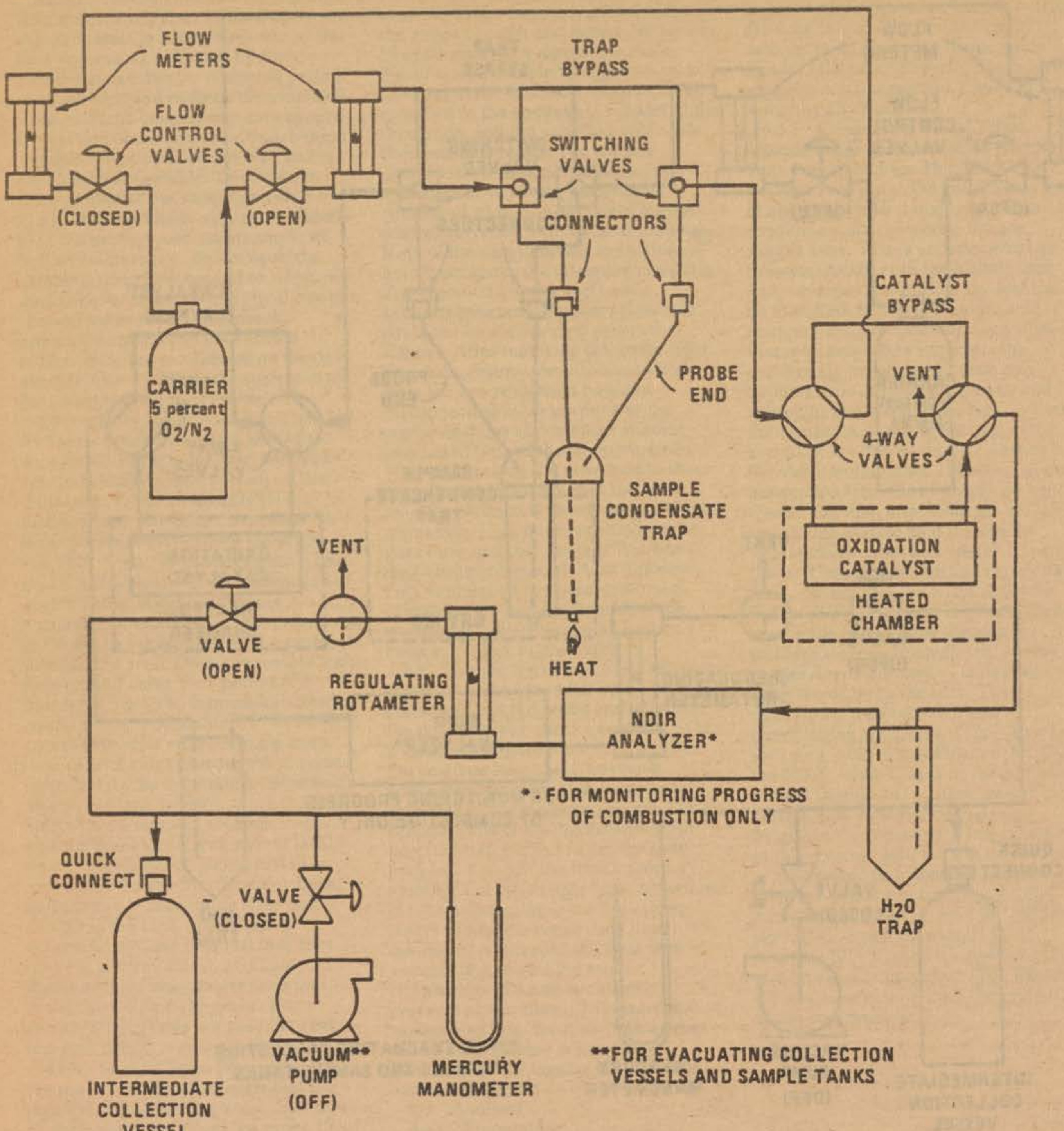

Figure 9. Condensate recovery and conditioning apparatus, collection of trap organics.

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4.3.3 Recovery of Condensate Trap Sample. Oxidation and collection of the sample in the condensate trap is now ready to begin. From the step just completed in paragraph 4.3.2 above, the system should be set up so that the carrier flow bypasses the condensate trap, bypasses the oxidation catalyst, and is vented to the atmosphere. Attach an evacuated intermediate collection vessel to the system and then, switch the carrier so that it flows through the oxidation catalyst. Monitor the NDIR and assure that the analyzer indicates a zero output level. Switch the carrier from vent to collect and open the collection tank valve; remove the dry ice from the trap and then switch the carrier flow through the trap. The system should now be set up to operate as indicated in Figure 9.

Begin heating the condensate trap. The trap should be heated to a temperature at which the trap glows a "dull red" (approximately 600° C) and should be maintained at this temperature for at least 5 minutes. During oxidation of the condensate trap sample, monitor the NDIR to determine when all the sample has been removed and oxidized (indicated by return to baseline of NDIR analyzer output). When complete recovery has been indicated, remove the heat from the trap. However, continue the carrier flow until the intermediate collection vessel is pressurized to a gauge pressure of 800 mm Hg (nominal). When the vessel is pressurized, vent the carrier; measure and record the final intermediate collection vessel pressure (P_f) as well as the barometric pressure (P_{bv}), ambient temperature (T_v), and collection vessel volume (V_v).

4.3.4 Analysis of Recovered Condensate Sample. After the preparation steps in paragraph 4.3.1 have been completed, the analyzer is ready for conducting analyses. Assure that the analyzer system is set so that the carrier gas is routed through the reduction catalyst to the FID (flow through the separation column and oxidation catalyst is optional). Attach the intermediate collection vessel to the tank inlet fitting of the TGNMO analyzer. Purge the sample loop with sample and then inject a preliminary sample in order to determine the appropriate FID attenuation. Inject triplicate samples from the intermediate collection vessel and record the values (C_{cm}). When appropriate, check the instrument calibration according to the procedures of paragraph 4.4.1.4.

4.3.5 Analysis of Gas Sample Tank. Assure that the analyzer is set up so that the carrier flow is routed through the separation column as well as both the oxidation and reduction catalysts. During analysis for the nonmethane organics the separation column is operated as follows: First, operate the column at −78° C (dry ice temperature) to elute the CO and CH_4. After the CH_4 peak, operate the column at 0° C to elute the CO_2. When the CO_2 is completely eluted, switch the carrier flow to backflush the column and simultaneously raise the column temperature to 100° C in order to elute all nonmethane organics. (Exact timings for column operation are determined from the calibration standard). Attach the gas sample tank to the tank inlet fitting of the TGNMO analyzer. Purge the sample loop with sample and inject a preliminary sample in order to determine the appropriate FID attenuation for monitoring the backflushed non-methane organics. Inject triplicate samples from the gas sample tank and record the values obtained for the nonmethane organics (C_{tm}). When appropriate, check the instrument calibration according to the procedures of paragraph 4.4.1.4.

4.4 Calibration. Maintain a record of performance of each item.

4.4.1 TGNMO Analyzer.

4.4.1.1 FID Calibration and linearity check. Set up the TGNMO system so that the carrier gas bypasses the oxidation and reduction catalysts. Zero and span the FID by injecting samples of the high value (5–10 percent) calibration gas (paragraph 3.3.1.3) and adjusting the instrument output to the correct level. Then check the instrument linearity by injecting triplicate samples of the low (5–10 ppm) and mid-range (500–1,000 ppm) calibration gases (paragraph 3.3.1.3). The system linearity is acceptable if the results (average for triplicate samples of each gas) are within ±5 percent of the expected values. This calibration and linearity check shall be conducted prior to analyzing each set of samples (i.e., samples from a given source test).

4.4.1.2 Oxidation Catalyst Efficiency Check. This check should be performed on a frequency established by the amount of use of the analyzer and the nature of the organic emissions to which the catalyst is exposed. As a minimum, perform this check prior to putting the analyzer into service.

To confirm that the oxidation catalyst is functioning in a correct manner, the operator must turn off or bypass the reduction catalyst while operating the analyzer in an otherwise normal fashion. Inject triplicate samples of the methane standard gas (paragraph 3.3.1.1) into the system. If oxidation is adequate, the only gas that will then reach the detector will be CO_2, to which the FID has no response. If a response is noted, the oxidation catalyst must be replaced.

4.4.1.3 Reduction Catalyst Efficiency Check. This check should be performed on a frequency established by the amount of use of the analyzer. As a minimum, perform this check prior to putting the analyzer into service. To confirm proper operation of the reduction catalyst, the operator must bypass the oxidation catalyst while operating the analyzer in an otherwise normal manner. After setting the carrier flow to bypass the oxidation catalyst, inject triplicate samples of the carbon dioxide standard gas (Section 3.3.1.2). The catalyst operation is acceptable if the average response of the triplicate CO_2 sample injections is within ±2 percent of the expected value and no one CO_2 sample injection varies by more than ±5 percent from the expected value.

4.4.1.4 System Operation Check. This system check should be conducted at a frequency consistent with the amount of use and the reliability of the particular analyzer. As a minimum, this system check shall be conducted before and after each set of emission samples is analyzed. If this system check is not successfully completed at the conclusion of the analyses, the results shall be invalidated. Operate the TGNMO analyzer in a normal fashion, passing the carrier flow through the separation column and both the oxidation and reduction catalysts. Inject triplicate samples of the two mixed gas standards specified in Section 3.3.1.4. The system operation is acceptable if, for each gas mixture, the average non-methane organic value for the triplicate samples is within ±3 percent of the expected value and no one sample analysis varies by more than ±5 percent from the average value for the triplicate samples.

4.4.2 Condensate Trap Recovery and Conditioning Apparatus Oxidation Catalyst Check. This catalyst check should be conducted at a frequency consistent with the amount of use of the catalyst, as well as, the nature and concentration level of the organics being recovered by the system. As a minimum, perform this check prior to and immediately after conditioning each set of emission sample traps.

Set up the condensate trap recovery system so that the carrier flow bypasses the trap inlet and is vented to the atmosphere at the system outlet. Assure that the tank collection valve is closed and then attach an evacuated intermediate collection vessel to the system. Connect the methane standard gas cylinder (Section 3.3.1.1) to the system's condensate trap connector (probe end, figure 4). Adjust the system valving so that the standard gas cylinder acts as the carrier gas; switch off the carrier and use the cylinder of standard gas to supply a gas flow rate equal to the carrier flow normally used during trap sample recovery. Now switch from vent to collect in order to begin collecting a sample. Continue collecting a sample in the normal manner until the intermediate vessel is filled to a nominal pressure of 300 mm Hg. Remove the intermediate vessel from the system and vent the carrier flow to the atmosphere. Switch the valving to return the system to its normal carrier gas and normal operating conditions. Set up the TGNMO analyzer to operate with the oxidation and reduction catalysts bypassed. Inject a sample from the intermediate collection vessel into the analyzer. The operation of the condensate trap recovery system oxidation catalyst is acceptable if oxidation of the standard methane gas was 99.5 percent complete, as indicated by the response of the TGNMO analyzer FID.

4.4.3 Gas Sampling Tank. The volume of the gas sampling tanks used must be determined. Prior to putting each tank in service, determine the tank volume by weighting the tanks empty and then filled with water; weight to the nearest 0.5 gm and record the results.

4.4.4 Intermediate Collection Vessel. The volume of the intermediate collection vessels used to collect CO_2 during the analysis of the condensate traps must be determined. Prior to putting each vessel into service, determine the volume by weighting the vessel empty and then filled with water; weigh to the nearest 0.5 gm and record the results.

5. *Calculations.*

Note. All equations are written using absolute pressure; absolute pressures are determined by adding the measured barometric pressure to the measured gauge pressure.

5.1 Sample Volume. For each test run, calculate the gas volume sampled:

$$V_s = 0.386\ V\left(\frac{P_t}{T_t}\right) - \left(\frac{P_{t_i}}{T_i}\right)$$

5.2 Noncondensible Organics. For each collection tank, determine the concentration of nonmethane organics (ppm C):

$$C_t = \frac{\dfrac{P_{tf}}{T_{tf}}}{\dfrac{P_t}{T_t} - \dfrac{P_{ti}}{T_{ti}}} \times \frac{1}{r} \times \sum_{j=1}^{r} C_{tm_j}$$

5.3 Condensible Organics. For each condensate trap determine the concentration of organics (ppm C):

$$C_c = 0.386\ \frac{V_v \times P_f}{V_s \times T_f} \times \frac{1}{N} \times \sum_{k=1}^{n} C_{cm_k}$$

5.4 Total Gaseous Nonmethane Organics (TGNMO). To determine the TGNMO concentration for each test run, use the following equation:

$C = C_t + C_c$

Where:

C = Total gaseous nonmethane organic (TGNMO) concentration of the effluent, ppm carbon equivalent.

C_c = Calculated condensible organic (condensate trap) concentration of the effluent, ppm carbon equivalent.

C_{cm} = Measured concentration (TGNMO analyzer) for the condensate trap (intermediate collection vessel), ppm methane.

C_t = Calculated noncondensible organic concentration of the effluent, ppm carbon equivalent.

C_{tm} = Measured concentration (TGNMO analyzer) for gas collection tank sample, ppm methane.

P_f = Final pressure of intermediate collection vessel, mm Hg., absolute.

P_{ti} = Gas sample tank pressure prior to sampling, mm Hg, absolute.

P_t = Gas sample tank pressure after sampling, but prior to pressurizing, mm Hg, absolute.

P_{tf} = Final gas sample tank pressure after pressurizing, mm Hg, absolute.

T_f = Final temperature of intermediate collection vessel, °K.

T_{ti} = Gas sample tank temperature prior to sampling, °K.

T_t = Gas sample tank temperature at completion of sampling, °K.

T_{tf} = Gas sample tank temperature after pressurizing, °K.

V = Gas collection tank volume, dscm.

V_v = Intermediate collection tank volume, dscm.

V_s = Gas volume sampled, dscm.

r = Total number of analyzer injections of tank sample during analysis (where j = injection number, 1 . . . r).

n = Total number of analyzer injections of condensible intermediate collection vessel during analysis (where k = injection number, 1 . . . n).

Standard Conditions = Dry, 760 mm Hg, 293°K.

6. *Bibliography.*

6.1 Albert E. Salo, Samuel Witz, and Robert D. MacPhee. "Determination of Solvent Vapor Concentrations by Total Combustion Analysis: A comparison of Infrared with Flame Ionization Detectors." Presented at the 68th Annual Meeting of the Air Pollution Control Association, Boston, Ma. Paper No. 75-33.2 June 15-20, 1975.

6.2 Albert E. Salo, William L. Oaks, Robert D. MacPhee. "Measuring the Organic Carbon Content of Source Emissions for Air Pollution Control." Presented at the 67th Annual Meeting of the Air Pollution Control Association, Denver, Colorado, Paper No. 74-190, June 9-13, 1974.

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federal register

Friday
October 5, 1979

Part VI

Department of Energy

Bonneville Power Administration

Allocation of Firm Electric Energy and System Reserve Energy From the Federal Columbia River Power System; Proposed Policy and Formula and Opportunity To Comment

DEPARTMENT OF ENERGY

Bonneville Power Administration

Proposed Policy and Formula To Guide Allocation of Firm Electric Energy and System Reserve Energy From the Federal Columbia River Power System and Opportunities for Public Review and Written Comment

AGENCY: Bonneville Power Administration (BPA or Bonneville), Department of Energy.

ACTION: Notice of Proposed Policy and formula to Guide Allocation of Firm Electric Energy and System Reserve Energy from the Federal Columbia River Power System (FCRPS) and Opportunities for Public Review and Written Comment.

SUMMARY: In 1976 BPA notified its preference customers that it would lack sufficient resources to fully meet their firm energy requirements after June 30, 1983. Since then, BPA has developed a proposed policy and formula to guide the allocation of firm energy and system reserve energy beginning July 1, 1983. This proposal reflects a public involvement effort underway since January 1978.

BPA is now publishing the proposal for widespread review and comment. This proposal provides initially for base allocations to existing preference customers from FCRPS hydro and net-billed thermal resources. As existing contracts with direct-service industrial and Federal agency customers expire between 1981 and 1993, the firm energy which becomes available will be reallocated to new and existing preference customers. As of July 1, 1991, any distinction between existing and new preference customers will be eliminated. Starting July 1, 1983, 15 percent of the available BPA firm energy will be reserved for awards to preference customers which implement approved conservation programs and achieve either at least 15 percent savings in their individual forecasted firm energy requirements in the 1989–1990 operating year or sooner, or all energy savings within their individual capabilities. It will be incumbent upon each preference customer to develop and implement a program that is tailored to its individual system characteristics.

BPA representatives will explain the proposed policy and answer questions at eight Public Information Forums—one in Portland, Oregon, October 31, and the others throughout the Pacific Northwest during the first week of November 1979. Public comment forums will be scheduled in 1980. Supporting documents will be available for review and copying at BPA headquarters 2 weeks after the date of publication of this Notice. Written comments are welcome at any time after publication and until 15 days after the last Public Comment Forum.

BACKGROUND: BPA and the Pacific Northwest face an energy insufficiency in the 1980's. While the region's utilities have reduced their forecasted future energy needs in all years through 1990, the May 1979 *Power Outlook* shows greater potential energy deficits in the mid-to-late 1980's than the 1978 *Power Outlook* indicated would probably be the case. The projected deficits are greater, despite the fact that the projected needs have been reduced. This is the result of further delays in the scheduled completion of thermal plants upon which the region is relying to meet its load growth needs.

BPA is the Federal power marketing agency which sells the power produced by 30 Federal hydroelectric projects constructed and operated by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation in the Pacific Northwest (defined by law to include Oregon, Washington, Idaho, Montana west of the Continental Divide, and portions of Wyoming, Utah, Nevada, and California). As a result of cooperative efforts to provide for supplementary thermal resource development, constructed by non-Federal interests, BPA also acquires and sells some thermal power. BPA supplies more than 50 percent of the total energy requirements in the Pacific Northwest.

BPA serves 160 customers in the Pacific Northwest and the Pacific Southwest. However, the Pacific Northwest Regional Preference Act of 1964 accords geographic preference and priority for the electric energy generated at Federal hydroelectric projects in the region to Pacific Northwest customers. Under the provisions of the Bonneville Project Act of 1937, as amended, public bodies and cooperatives (BPA's preference customers or PC's) in the Pacific Northwest are entitled to statutory preference and priority for the BPA firm energy available for sale. Currently, BPA has power sales contracts with 116 preference customers.

BPA also has power sales contracts to sell firm energy to 6 Federal agencies and 17 direct-service industrial (DSI or DSI's) customers located in the region. Under the geographic preference clause of the Hungry Horse Dam Act of 1944, firm energy is also sold to the Montana Power Company, an investor-owned utility (IOU) or IOU's), for use within the State of Montana.

In the past, BPA generally had sufficient power available to satisfy the requirements of all customers, including those to whom preference and priority are not accorded by law. For some years, BPA has known that it could not continue to contract to meet the firm energy requirements of its customers without acquiring additional resources. The necessary resources have not materialized. Therefore, BPA has notified its existing preference customers (PC or PC's) that it will not have sufficient firm energy available after June 30, 1983, to continue to meet their load growth and satisfy BPA's other firm energy commitments. In August 1973, firm power sales contracts with investor-owned utilities (IOU or IOU's) expired. BPA's power supply was not adequate to enable it to offer new power sales contracts for firm energy to the IOU's. In addition, BPA has stated that it will be unable to offer new power sales contracts on the same terms and conditions to its existing direct-service industrial (DSI or DSI's) customers when their present contracts expire. Representatives of the DSI's have indicated that they will apply for service from their local utilities.

BPA will serve its existing Federal agency customers until their contracts expire. Under the provisions of the Bonneville Project Act Federal agencies are not entitled to statutory preference and priority for the BPA firm energy available for sale. They will have to apply for service from their local utilities after their contracts expire or make other arrangements. BPA anticipates that existing PC's and preference applicants (PA's) will apply for the firm energy which will become available for allocation after existing BPA contracts with DSI's and Federal agencies expire.

BPA recognizes that its marketing policies affect the well-being of the region's economy and the resource planning of existing and prospective customers. Therefore, BPA believes a final allocation policy and formula, a final environmental impact statement, and the BPA conservation program specifics should be completed prior to the date existing power sale contracts begin to expire—1981 in the case of nonpreference customers and 1983 in the case of preference customers.

Otherwise, prolonged uncertainty over the substance and mechanics of a long-term allocation policy affects the capability of BPA's customers to provide for energy supplies which the BPA allocations cannot satisfy. If PC's are overly optimistic about what their share of BPA firm energy is likely to be, shortages could occur whose impacts would vary in intensity from place to place. If preference utilities are unduly pessimistic, they may construct excess generating capacity. IOU's are also affected by the uncertainty about what future requirements will be imposed on them, depending on whether or not new public bodies and cooperatives are formed which receive BPA allocations of firm energy, and whether or not the IOU's receive applications for service from DSI's and Federal agencies which cannot be readily served by BPA preference customers.

Since the DSI's and the Federal agencies must secure alternative power supplies after their current contracts with BPA expire, BPA expects that the costs of their energy supplies will rise. The policy does not cushion the economic impact on the DSI's and Federal agencies which will occur when BPA service ends. Approximately 85 percent of the composite BPA industrial customer load (ten DSI's at 14 sites) in calendar year (CY) 1978, can readily be served by BPA's existing PC's. Seven DSI's with plants at seven sites account for the remaining 15 percent of the composite industrial customer load in CY 1978. Presumably, these industries will apply for service from the nearest IOU's or make other arrangements.

BPA is proposing that all firm loads served by a PC be included in its net firm energy requirements eligible for an allocation of BPA firm energy, with one exception: new or expanding single loads which equal or exceed 10 average megawatts in a 3-year period commencing from the date of initial service and which have not been contracted for or committed to prior to September 1, 1979. Those amounts of any loads which BPA or any Pacific Northwest utilities contracted to serve as nonfirm loads prior to September 1, 1979, will be regarded as new or expanding single loads if they become firm loads. Some examples of present nonfirm loads are the interruptible (first) and reserve (second) quartiles of the current DSI loads.

Under its existing contracts, BPA markets interruptible energy for meeting loads specifically suited for this lower quality supply. Approximately 25 percent of the DSI load is suitable for this supply. This energy, which is generally regarded as energy above critical streamflows, is available when FCRPS capability exceeds what is needed to meet contracted firm energy requirements. BPA markets this energy under contracts which contain provisions that permit BPA to interrupt deliveries for any purpose. This facilitates efficient operation of the FCRPS, provides an assured market for nonfirm energy, and supplies a load without requiring additional firm generating resources. BPA proposes to contine marketing interruptible energy to PC's which have loads suitable for such energy. Since BPA will no longer provide direct service to the DSI's after contracts expire, local utilities may purchase interruptible energy to serve these types of loads.

Under its existing contracts, BPA markets a block of energy to the DSI's which provides the FCRPS with both capacity and energy reserves. Approximately 25 percent of the DSI load is served from this supply. BPA makes use of these system reserves by restricting deliveries to the DSI's when necessary to protect BPA's firm energy commitments to its PC's or to back up a PC's own generation. BPA proposes to continue marketing system reserve energy after the current DSI contracts expire. However, the system reserve energy will be made available to PC's with BPA retaining rights to restrict deliveries for its own and contract purposes.

Six Federal agencies with eight points of delivery, accounting for 68 percent of the composite BPA Federal agency customer load in calendar year 1978, can readily be served by BPA preference customers. BPA is proposing that these loads, which are considered firm, be included in these preference customers' net firm energy requirements eligible for an allocation of BPA firm energy. The remaining two agencies with three points of delivery, that account for 32 percent of the composite BPA Federal agency customer load in calendar year 1978, will have to apply for service from the nearest IOU's or make other arrangements.

BPA has contracted to meet the net firm energy requirements of existing PC's who are computed demand customers, and the requirements, including contract demands, of all other existing PC's subject to limitations on obligations to serve large new loads and the right to restrict power delivery obligations on proper notice. In accordance with provisions in these contracts, BPA issued a Notice of Insufficiency on June 24, 1976. The Notice states that BPA cannot meet PC firm energy load growth after July 1, 1983, except for those utilities whose loads are less than the guaranteed minimum allocation. Allocation formulas incorporated in the existing contracts determine allocations of firm energy for the duration of each contract.

Prior to the Notice of Insufficiency, BPA had advised new PA's that firm energy would not be available for sale until additional resources became available and/or existing contracts expired. Nonetheless, newly formed public bodies and cooperatives have applied for service. BPA anticipates that other public bodies and cooperatives may yet be formed which will also request allocations of firm energy.

Pursuant to 16 U.S.C. 832–832l, 16 U.S.C. 837–837h, 16 U.S.C. 838–838k, 16 U.S.C. 825a, 43 U.S.C. 593a, and other applicable statutes, the BPA Administrator has developed a proposed allocation policy and formula to guide the reallocation of the firm energy and system reserve energy which will become available as all outstanding power sales contracts expire between May 11, 1981, and September 20, 1994, and to guide the allocation of resources available to the FCRPS each operating year in circumstances where they may be augmented or reduced. The policy also provides for revised allocations among PC's and service to new as well as existing PC's. The policy proposal is included in Part I of this notice.

In brief, BPA is proposing that public bodies and cooperatives it does not presently serve will be required to submit applications 30 months or more before firm energy is scheduled to become available due to contract expirations and resource additions. From July 1, 1983, through June 30, 1991, new preference customers which satisfy the criteria for service specified under (1) *Class(es) of Customer(s) to be Served* in the proposed policy will be eligible, as a group, for allocations totalling up to ⅔ of the firm energy available for allocation or reallocation during the operating year in which they first receive service. Starting with the second year of service, they will receive allocations on the same basis as existing BPA customers.

From July 1, 1983, through June 30, 1991, existing PC's will receive allocations in accordance with the provisions in their current contracts, if they adopt a satisfactory conservation program and implementation plan. By extending the contract provisions, service continues to more than 60 percent of BPA's existing PC's which might otherwise be without a BPA firm energy allocation. These customers will realize considerable savings in energy costs, since they will not have to purchase higher cost energy elsewhere.

The economic impact on all PC's depends on a number of variables such as (1) the actual amount(s) of additional firm energy available from BPA each operating year, (2) the number and size of new preference customers served by BPA, (3) the effectiveness of the customers' conservation programs, taken individually and in the aggregate, (4) the timing of applications by preference applicants, and (5) the actual resource cost(s) of resource additions, which may or may not be reflected in forecasts.

After July 1, 1991, BPA will allocate energy on the basis of the relationship of each customer's total net firm energy requirements to all customers' total net firm energy requirements multiplied by the total amount of power BPA has available for allocation, less the 15 percent for the conservation reserve. Individual customer allocations will be increased for achievements in energy conservation, as provided under (4) *Conservation* in the proposed policy.

Prior to July 1, 1991, all BPA allocations will not be calculated on a pro rata basis and, therefore, they will not reflect a full sharing of the economic benefits and costs of BPA firm energy among BPA customers. The policy includes a feature, (8) *Sharing of Benefits and Costs*, to assure that the distribution of benefits and costs will more closely approximate what would otherwise be the case after July 1, 1991, when all PC's will receive pro rata allocations. This feature may cushion the economic change which would otherwise occur at that time by providing for a transition adjustment to the extent the new contracts permit.

BPA is proposing that allocations of firm energy be made under the provisions of new contracts to be offered to existing PC's and to PA's eligible for an allocation. The new contracts will become effective when executed and terminate July 1, 2001. These contracts will contain allocation provisions which will be effective July 1, 1983, or later in certain circumstances, for the period(s) specified in the contract provisions. BPA recognizes that an existing preference customer may elect to continue with its existing contract until expiration, or not to sign the new contract offered. The policy has addressed this possibility.

The allocation policy development process reflects prior consultation with BPA customers, state and local governments, the PNW Congressional delegation, other Federal agencies, public interest groups, and consumers. BPA initiated the public involvement process by publishing a "Notice of Intent to Develop Formula for Allocation of Electric Energy" in the **Federal Register** (43 FR 3611) and announcing that it would follow the BPA "Procedure for Public Participation in Marketing Policy Formulation" (42 FR 62950, December 14, 1977) to offer its customers and the public the opportunity to participate in formulating the policy and formula.

The Notice of Intent linked the 1976 Notice of Insufficiency, the post-July 1, 1983 allocations by the existing contract formula, and the need for a long-term policy and formula to guide the allocations of firm energy which will become available as a result of contract expirations, the allocations of firm energy which becomes available to the FCRPS as new resources are acquired, irrespective of source, or the revised allocations occasioned by reductions in firm energy available for marketing. The Notice of Intent also indicated that it is probable that new public bodies and cooperative will be formed which would be eligible for an allocation of BPA firm energy, and that their applications would have to be considered when BPA allocates firm energy.

BPA publicized the allocations policy development process through public mailings, news releases, and advertisements. The process to date has included briefings, discussion meetings, and analyses of views and suggestions received from the public on the development of policy alternatives, allocation policy procedure, and supporting analyses. The staff summary of the public comments will be made avialable to anyone who request a copy.

The allocation policy issues identified and discussed most frequently by the public include:

(1) the class(es) of BPA customer(s) to be served (current preference customers, new preference customers, Federal agencies, DSI's Pacific Northwest IOU's, Pacific Southwest customers served by the Intertie, and British Columbia Hydro);

(2) the extent to which BPA should require customers to commit their own non-Federal assured resources to meet their own load requirements before BPA determines their allocations;

(3) the types of loads to be served (i.e., the end uses of the firm energy BPA wholesales to its utility customers who, in turn, sell it, at retail, to consumers);

(4) the methods employed to determine load requirements and the amount of energy expected to be available to meet those loads;

(5) the extent and availability of sytem energy reserves;

(6) the durations and terms of the allocations;

(7) minimum allocations to preference customers;

(8) grades of power;

(9) rates charged for firm power; and

(10) conservation.

BPA conducted a policy analysis which addressed the issues identified in the Notice of Intent and considered all the public comments.

BPA received over 140 letters in response to the Notice of Intent and subsequent requests for public comments and suggestions. The majority of the respondents (about 70 percent) were from the general public. The remainder were utility and utility organizations, governors and state agencies, counties and municipalities, granges and other interested groups, the United States Navy, a state legislator, the Bureau of Mines, and a direct-service industry organization.

Approximately one-third of the comments related to "class of BPA customers." The most common remark was to give priority to preference customers. The next largest group favored equal sharing of resources among public agencies and investor-owned utilities. A substantial minority thought that BPA should serve all users equally without preference.

The next two largest categories of comment pertain to "rates" and "types of consumer sector loads served." With respect to rates, the most often mentioned rate factor was cost of production. There were extensive comments proposing a wide variety of rate designs including lifeline rates, interruptible services, peak load pricing, inverted rates, and others. There was no consensus on a preferred scheme. With respect to types of consumer sector loads served, the most frequent comment was to give first priority to domestic and rural consumers. The next largest group noted that the needs of people should be met before the needs of industry. A substantial minority would ignore the types of loads served and distribute power equally to all users.

The remaining comments largely addressed six other allocation issues: load determination, customer resources committed to load, grades of power, notice and duration, minimum allocations, conservation, amounts of power to be allocated. A wide variety of approaches to each issue was suggested.

In recent months, the analysis has concentrated on six major alternatives which incorporate varying approaches to the issues. BPA tested their technical feasibility and potential ramifications. As a result, the alternatives and associated methods of allocation have undergone modification. The proposed policy and other alternatives in their current configurations are displayed in the table entitled *Comparison of Proposed and Alternative Allocation Policies* included in Part IV of this Notice.

BPA considered the following evaluation criteria in assessing the alternatives: technical adequacy, reasonableness, potential economic and environmental impacts, equity, conformity with existing statutes, conservation, policy continuity, and ease of administration and public understanding. As a result, BPA proposes to implement Allocation Policy Alternative 3, subject to public comment, and additional economic and environmental analyses contemplated under applicable statutes and rules and regulations.

BPA believes that this proposal serves the public interest, since it (1) provides a method to efficiently utilize and promote widespread use in the Pacific Northwest of existing and prospective Federal firm energy resources, and (2) relies on conservation to supplement the limited Federal resource. Conservation represents the primary means available to the region in the 1980's to cope with energy deficits. The proposed policy could be implemented under existing statutory authorities, and it is conducive to achievement of many regional and national energy-related goals incorporated in State and Federal laws.

The BPA allocation proposal minimizes the degree of deviation from current BPA policies upon which BPA customers have long relied and on the basis of which they have made substantial financial and other commitments. The primary changes are to (1) make the Federal energy available to existing preference customers and new preference applicants; (2) establish a conservation reserve totalling 15 percent of the total firm energy available for allocation to preference customers; (3) require each preference customer to institute a conservation program/implementation plan as a condition for eligibility for additional allocations of firm energy from the conservation reserve; (4) terminate the fixed base allocation and the 25 MW minimum allocation to existing preference customers on July 1, 1991; (5) end direct firm energy sales to current Federal agency and DSI customers after their existing power sales contracts expire, (6) establish an offset energy arrangement to assure that the sharing of benefits and costs among BPA customers will more closely approximate what will occur after July 1, 1991, when all customers will receive pro rata allocations based on their net firm energy requirements; (7) market system reserve energy to PC's as a separate class of power; and (8) market interruptible energy to PC's to serve loads suitable for this lower quality of supply.

BPA will hold eight Public Information Forums on this proposed policy. One, a more technical session, will be held in Portland, Oregon, October 31, 1979. The other seven will be held throughout the Pacific Northwest during the first week of November 1979 to explain the proposal, present the general findings of its supporting analyses, and answer questions on the proposal and alternatives. BPA will also hold Public Comment Forums to receive oral comments at a future date or dates in 1980 to be announced later in a separate Notice and by mail and newspaper advertisement. Interested parties are urged to send their written comments on the proposal to BPA as soon as possible after this Notice is published. Written comments should be submitted to the Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212.

The expiration date of the public comment period will be firmly established at the time the Public Comment Forums are scheduled and the dates announced. BPA accepts written comments on a proposed marketing policy at any time after it is announced and until 15 days after the date of the last Public Comment Forum. Following the public comment period, the Administrator will modify the allocation policy proposal to the extent he deems appropriate, considering the comments received, and publish the revised proposal in the **Federal Register.**

DATES: Public Information Forums will be held on the following dates at the locations indicated. At 9 a.m. on October 31, 1979, at the BPA Auditorium, 1002 NE. Holladay Street, Portland, Oregon. At 7:30 p.m. on November 5, 1979, at Mt. Hood Room, Travelodge at the Coliseum, 1441 NE. Second Avenue, Portland, Oregon; and The Forum, Walla Walla Community College, 500 Tausick Way, Walla Walla, Washington. At 7:30 p.m. on November 6, 1979, at Forum R, Eugene Hotel, 222 East Broadway, Eugene, Oregon; and City Council Chambers, 140 South Capitol, Idaho Falls, Idaho. At 7:30 p.m. on November 7, 1979, at Terrace Room A, Ridpath Hotel, West 515 Sprague, Spokane, Washington; and Phoenix C and D Rooms, Hyatt House-Seattle, Sea-Tac International Airport, 17001 Pacific Highway South, Seattle, Washington. At 7:30 p.m. on November 8, 1979, at Colt 44 and 45 Rooms, Outlaw Inn, 1701 Highway 93 South, Kalispell, Montana.

FOR FURTHER INFORMATION CONTACT:

Ms. Donna Lou Geiger, Public Involvement Coordinator, P.O. Box 12999, Portland, Oregon 97212, 503-234-3361, ext. 4261. Toll-free numbers for Oregon callers 800-452-8429; for callers from Washington, Idaho, Montana, Utah, Nevada, Wyoming, and California 800-547-6048.

Mr. John H. Alberthal, Area Manager, Room 201, 919 NE. 19th Avenue, Portland, Oregon 97208, 503-234-3361, ext. 4551.

Mr. Ladd Sutton, District Manager, Room 206, 211 East Seventh Avenue, Eugene, Oregon 97401, 503-345-0311.

Mr. Ronald H. Wilkerson, Area Manager, Room 561, West 920 Riverside Avenue, Spokane, Washington 99201, 509-456-2500, ext. 2518.

Mr. Gordon H. Brandenburger, District Manager, P.O. Box 758, Kalispell, Montana 59901, 406-755-6202.

Mr. Joseph J. Anderson, District Manager, Room 314, 301 Yakima Street, Wenatchee, Washington 98801, 509-662-4377, ext. 379.

Mr. George A. Tupper, Area Manager, Room 250, 415 First Avenue North, Seattle, Washington 98109, 206-442-4130.

Mr. Harold M. Cantrell, Area Manager, West 101 Poplar, Walla Walla, Washington 99362, 509-525-5500, ext. 701.

Mr. Martin C. Derksema, District Manager, 531 Lomax Street, Idaho Falls, Idaho 83401, 208-523-2706.

SUPPLEMENTARY INFORMATION: Two weeks after the date of publication of this Notice, the major studies and analyses which have been used will be available for review and copying at BPA headquarters located at 1002 Northeast Holladay Street, Portland, Oregon. They are:

1. *Draft* Option Papers Evaluating BPA and Regional Power System Alternatives;
2. *Draft* Allocation Policy Discussion Papers;
3. Direct-Service Industry Impact Study;
4. Computer Listings and Tables;
5. Summary of Public Comment;
6. Skidmore, Owing and Merrill (SOM) Report;
7. Northwest Energy Policy Project (NEPP) Report;
8. NRDC Alternative Scenario.
9. Power Outlook, May 1979.

Environmental impacts of the proposed allocation policy and alternatives will be analyzed in an Environmental Impact Statement (EIS). A Notice of Intent to Prepare an EIS on the Proposed Policy and Formula to Guide Allocation of Firm Electric Energy and System Reserve Energy from the FCRPS will be published in the **Federal Register.** BPA will solicit public views on the scope of the Draft EIS.

BPA has included Draft Tables and an Exhibit in Part IV of this Notice. They are:

1. *Estimated Net Federal Resources Available for Allocation;*
2. *Basic Load Resource Data;*
3. *BPA Preference Customers' Estimated Firm Energy Requirements,*

Operating Years 1983–84 through 1997–98;

4. *Existing BPA Preference Customers: Estimated System Loads, Calculated BPA Allocations, BPA Obligations, and Utility Deficits, By Year of Contract Expiration;*

5. *Federal Agency Customers of BPA;*

6. *Direct-Service Industrial (DSI) Customers of BPA;*

7. *Comparison of Proposed and Alternative Allocation Policies;* and

8. *Exhibit: Section 22 of the General Contract Provisions attached to Existing Power Sales Contracts.*

The tables contain preliminary or estimated information which is subject to change. Nonetheless, BPA believes the information presented may substantially assist its customers and the public in understanding the proposal and its implications.

I. Proposed Policy and Formula to Guide Allocation of Firm Electric Energy and System Reserve Energy From the FCRPS

(1) *Class(es) of Customer(s) to be Served:*

(a) BPA will accord preference and priority to existing preference customers (customers which now have firm power contracts), new preference customers (customers receiving an allocation during the first year of service), and preference applicants (public bodies and cooperatives which have pending applications). Preference customers will share the firm energy which becomes available for allocation as Direct-Service Industrial (DSI or DSI's) and Federal agency contracts expire or new resources are added to or subtracted from the system which may or may not be anticipated and reflected in BPA's resource data.(*1*)

(b) As their contracts expire, DSI's and Federal agencies may apply to their local utilities for service.

(c) BPA will continue to provide not less than 221 average megawatts (MW) of firm power for use within the State of Montana.(*2*)

(d) BPA will serve any preference applicant which BPA determines is eligible for an allocation and which BPA determines (1) can receive power from BPA in a manner consistent with BPA's policies and practices for the delivery of power to its customers, (2) has acquired or can be reasonably expected to acquire a power supply from non-BPA source(s) sufficient to meet that portion of its load not met by a BPA allocation, and (3) can receive or can be reasonably expected to receive an allocation of energy over its own or other non-Federal facilities, or available BPA facilities.

(2) *Customer-owned assured Resources:* The disposition of customer-owned, non-Federal resources can affect the allocation of Federal power. An amount of assured resources for each customer will be determined for each operating year. The assured resources will reduce the customer's requirements eligible for allocation. The capability of assured resources are determined by a customer's hydrogeneration resource based on adverse streamflows, a customer's thermal-generating resources based on probable or more conservative fuel and generating conditions, and the firm capability of a customer's other resources acquired by contract.

Starting July 1, 1983, BPA will use the existing preference customer's 1975–76 assured resources in determining its base allocation of firm energy. BPA will determine a new preference customer's base allocation assuming its 1975–76 assured resources are zero, unless the new customer has obtained some or all of the resources of another Pacific Northwest utility. For all other allocations prior to July 1, 1991, and all allocations thereafter, any resources an existing preference customer owns or acquires by purchase and uses in its own system, at a resource cost equal to or less than the resource cost of BPA firm energy, will be considered assured resources.

Starting July 1, 1983, BPA will require each customer to either use in its own system any resources which can reasonably be made available to meet its own firm loads, or to make these resources available for purchase at cost including a reasonable rate of return. These resources may be purchased first by BPA, in accordance with existing statutory authorities, for its own use or on behalf of its preference customers, second by BPA's preference customers, and third by other Pacific Northwest utilities. If the customer elects to sell or dispose of these resources in a different manner, then the amount of its BPA allocation will be reduced by the amount of the resources so sold or disposed of.(*3*)

(3) *Type(s) of Load(s) Served:* To calculate the loads eligible for an allocation of BPA firm energy, existing and new preference customers may include all firm loads served (including, but not necessarily limited to, domestic or residential, commercial, industrial, irrigation, and public authorities), except new or expanding single loads which equal or exceed 10 average MW in a 3-year period commencing from the date of initial service, which have not been contracted for or committed to prior to September 1, 1979.(*4*) Those amounts of any loads which BPA or any Pacific Northwest utilities contracted to serve as nonfirm loads prior to September 1, 1979, will be regarded as new or expanding single loads if they become firm loads, e.g., the interruptible and reserve quartiles of the current DSI loads which are considered non-firm. Federal agency loads now served by BPA which will be served by preference customers after existing Federal agency contracts expire may be included as preference customer loads eligible for an allocation.

(4) *Conservation.* BPA believes that conservation should be addressed in the formulation and implementation of any allocation policy. The potential exists for a significant further reduction in regional electric energy usage through conservation. Achievement of feasible and effective conservation through implementation of the proposed BPA allocation policy would serve the public interest by efficiently utilizing and promoting the widespread use of existing and prospective Federal firm energy resources.

BPA will reserve 15 percent of the total firm energy available for allocation to preference customers. Additional allocations will be awarded to preference customers from the conservation reserve as a reward for their individual conservation achievements. To be eligible for an additional allocation from the conservation reserve, each preference customer and each preference applicant must establish a conservation program and implementation plan designed to (a) achieve a phased reduction of at least 15 percent of what its total load would otherwise have been, absent its program, in the 1989–1990 operating year or earlier if reasonably practicable; or (b) to achieve all feasible conservation measures which can be instituted by the customer or applicant (if judged to be less than 15 percent) by the 1989–1990 operating year or earlier if reasonably practicable.(*5*)

An existing preference customer will prepare and submit its conservation program and implementation plan to BPA by January 1, 1982.(*6*) Each preference applicant will submit a conservation program and implementation plan to BPA with its application for an allocation of firm energy. The program must be implemented as soon as reasonably practicable. BPA will review all conservation program/implementation plan submissions to determine the potential energy savings that can be achieved.

If BPA determines that a program under review is capable of achieving a

15 percent savings in the customer's or applicant's forecasted firm energy requirements in the 1989–1990 operating year or sooner, or will achieve all energy savings which are within the customer's capability (if judged to be less than 15 percent), then the customer or applicant will be eligible for an additional allocation of energy. The resulting total allocation will be determined by dividing the product of the allocation formula by 0.85 (see 7. *Duration and Terms of Allocations).*

If BPA considers a proposed program deficient, the customer or applicant may subsequently submit a program amendment to remedy the deficiency in its original program submission. BPA would then provide in the appropriate operating year the additional allocation for which the customer or applicant is eligible. If a customer or applicant fails to develop a program to achieve either a 15 percent savings or the conservation within the customer's capability, then the customer will not be eligible for any allocations of energy from the conservation reserve.

If BPA determines that a customer's program will result in energy savings exceeding the 15 percent goal in any operating year, then the customer's or applicant's total allocation will be increased 1 percent for each 1 percent that the savings exceed 15 percent. This adjustment will be made for the operating year in which the savings are projected to exceed 15 percent. This reward can be allocated during the operating year beginning July 1, 1985, and during any succeeding operating year.

If, after adjusting the allocations for customers which (1) realize 15 percent conservation, and (2) realize greater than 15 percent conservation, some amount of the firm energy reserved for conservation rewards remains unallocated, the Administrator will determine how to dispose of this energy.

BPA is proposing a conservation program requirement, specifying a conservation goal, and prescribing an incentive for individual customers and applicants to attain the goal by providing additional allocations for adequate program design and implementation. However, BPA does not consider it appropriate to prescribe a uniform set of conservation program criteria invariably applicable to all customers and applicants. It will be incumbent upon each customer and applicant to develop and implement a program that is tailored to its individual system characteristics.

BPA will develop and publish its program standards, including evaluation criteria, annual reporting requirements, and program progress review procedures by the time the final allocation policy is promulgated. BPA's program standards may also identify those measures or actions considered conducive to achievement of the desired savings. Upon request, BPA will consult with customers and applicants and assist in the design of programs which could feasibly provide the desired savings.

Each program proposal should identify and provide support for the overall savings projected. The program proposals may include preexisting and proposed new conservation measured as well as measures required by others which could result in electric energy savings. Each customer or applicant must provide assurances that the measures will be implemented at the earliest possible date, and that each measure can reasonably be expected to achieve the specific savings associated with it. BPA and the customer will jointly evaluate individual program progress annually.

Beginning July 1, 1983, BPA will provide annual notice to its customers of the adjustments for conservation which will result in a change to the customers' allocations simultaneously with their allocations for the operating year 2 years hence. Full allocations will be made in OY's 1983 and 1984 assuming good faith efforts to conserve and the adoption of sound programs by BPA customers.

On January 1, 1984, and each year thereafter, each customer will submit a progress report and may submit a program and/or plan amendment. However, program and plan amendments may be submitted at any time. Beginning July 1, 1985, BPA will expect to have observed tangible progress. BPA will also expect its customers to show evidence of progress each operating year thereafter, and to sustain their conservation efforts throughout the contract period. BPA will not make any allocations from the conservation reserve for the appropriate operating year to customers who discontinue their program or fail to achieve the desired savings.

(5) *Load Determinations and Resource Availability:* BPA will review and approve all estimates of the firm energy requirements of customers and applicants for the purpose of allocating BPA firm energy.(7) BPA will use the customers' and applicants' net firm energy requirements to determine their allocations. Net firm energy requirements are a customer's or applicants' total system firm energy load less its assured resources (see (2) *Customer-Owned Assured Resources).*

Starting July 1, 1982, and on each July 1 thereafter, BPA will provide annual projections of the aggregate FCRPS firm energy resources available for allocation, by operating year, for the 10-year period ahead. These annual projections will represent BPA's minimum firm energy obligation for each operating year within the rolling 10-year period.

(6) *System Reserves.* BPA presently markets to the DSI's a block of energy providing the FCRPS with both capacity and energy reserves. This block of energy accounts for approximately 25 percent of DSI load (the second quartile). BPA makes use of these system reserves by restricting deliveries to the DSI's when it is necessary to protect BPA's firm energy commitments to its preference customers. They are also used to the extent that BPA is committed to back up a preference customer's own generation. BPA exercises its restriction rights directly through BPA-controlled load-control devices.

BPA believes that system reserves are needed even after the current DSI contracts expire. These needs include both BPA requirements and those of preference customers who wish to contract for their own specific reserve requirements.

The system reserve energy will be made available to preference customers with BPA retaining rights to restrict deliveries for its own and contract purposes. On July 1, 1982, and every July 1 of succeeding operating years, BPA will estimate the amount of this system reserve energy that will be made available for sale 2 operating years hence. Initially, the amount will equal about 25 percent of the total DSI contract demand specified in the contracts which have expired by the given operating year. If BPA determines that the amount of system reserves that will be needed for forced outages and other purposes must be changed, BPA will make an equivalent change in the amount of firm energy available for allocation.

The system reserve energy will only be made available to preference customers who can use such energy for their loads and who agree to provide BPA with contract rights to: (a) restrict deliveries to satisfy either capacity or energy (or both) reserve requirements, and (b) permit BPA to restrict loads directly with BPA-controlled load-control devices. If the BPA supply of system reserve energy is not sufficient to meet the needs of all customers, then each customer may purchase pro rata shares of the available system reserves.

BPA recognizes that many preference customers may not directly serve loads suitable for restriction. All customers should be able to directly share in the economic advantage of the reserve energy with other preference customers who serve such loads. Because it would be administratively infeasible to allocate system reserves to all customers in proportion to their net requirements and provide for the many complex, multiparty rate and operating contracts to implement an equitable sharing of system reserves, BPA will establish a special higher rate for this system reserve energy so that the benefits will accrue to all customers through lower BPA firm energy rates. This system reserve rate will be generally based on the average wholesale power costs of all preference customer resources, including purchases from BPA, used to meet firm loads with adjustments for the value of system reserves provided either in the average rate or in rate credits, if any, if deliveries of such energy are restricted. Such rates will be established as a normal part of BPA rate proceedings.

(7) *Durations and Terms of Allocations:* All BPA allocations of firm energy and all estimates of system requirements are subject to the adjustments for energy conservation described under (4) *Conservation.*

BPA will offer to contract to supply the net firm energy requirements of computed demand customers and the requirements, including contract demands of all other existing preference customers, subject to limitations on obligations to serve large new loads and the right to restrict power delivery obligations on proper notice. All contracts will contain allocation provisions to implement the final policy when promulgated. These provisions will take effect July 1, 1983, or later, depending on the date of execution of the contract. They terminate July 1, 2001.

Preference applicants who otherwise qualify may also receive an allocation if they apply to BPA after the final policy is promulgated and 30 months or more before firm energy and system reserve energy are scheduled to become available as a result of contract expirations, resource additions, or any operating year after July 1, 1991, when allocations are revised for all preference customers.

BPA will use the following formula for determining the allocations to preference applicants and the allocations to existing and new preference customers:

Allocation Formula

BPA will determine the amounts of (A/B)(C) and (D) for each customer.

A customer's total allocation, prior to any additional allocations for conservation and adjustments for sharing of benefits and costs, will equal:

(1) (D), limited to the customer's net requirements, for those customers where (D) is greater than their respective (A/B)(C) amounts.

(2) For all other customers, the pro rata share of the firm energy, based on net requirements, which remains available for allocation after deducting the total amount allocated under (1) above, from the total amount available for allocation (C). However, the pro rata share will not be less than a customer's (D), limited to that expressed in average megawatts.

A=Customer's total net firm energy requirements.
B=Total of all customers' net firm energy requirements.
C=Total amount of firm energy BPA has available for allocation or has allocated, less the 15 percent reserved for conservation incentives.
D=The allocation of the customer adjusted by a factor of 0.85 for conservation. For all customers, the value of "D" becomes zero as of July 1, 1991. An existing preference customer's base allocation prior to July 1, 1991, and a new preference customer's base allocation during the first year of service prior to July 1, 1991, will be computed in accordance with the provisions of this section.

To determine the base allocation for its existing preference customers, BPA proposes to continue the terms of Section 22 of the General Contract Provisions attached to its current firm power sales contracts in the new contracts to be offered existing preference customers. However, this base will be adjusted for the conservation reserve by multiplying by a factor of 0.85. The allocation can be increased for achievements in energy conservation as provided under (4) *Conservation.*

Except for the City of Tacoma and those existing preference customers formerly served by the city of Tacoma which have, contracts with provisions containing modified allocations, each existing preference customer's allocation under Section 22 consists of:

(a) *a hydro allocation* based on 1975–76 actual system firm energy requirements less assured resources. However, if this results in a net firm energy requirement that is less than 25 average MW, then the customer will recieve a hydro allocation not to exceed 25 average MW;

(b) *a thermal allocation* which is equal to a fraction whose numerator is *the lesser* of *either* actual load growth from OY 1975–1976 through OY 1982–1983, or 103 percent of the forecasted load growth, as of December 1973, for the same period *divided* by the total load growth of all existing preference customers for the same operating period (OY's 1975–76 through 1982–83) but *limited* for each customer to 103 percent of the December 1973 load forecast and *multiplied* by a factor of 1881.8 MW. (This factor was determined from BPA's 30 percent share of the Trojan nuclear plant, BPA's 100 percent shares of WPPSS #1 and #2 plants, and BPA's 70 percent share of WPPSS #3 plant (or WNP #1, #2, and #3). If the city of Eugene withdraws any power from Trojan, or if BPA acquires power from any additional net-billed thermal projects, the 1881.8 MW is subject to change.)

(c) A third allocation exists for 37 participants in the Canadian Entitlement Exchange Agreement. Under this allocation, BPA will provide annually an amount of energy equal to the difference between each participant's 1983–84 share of Canadian Storage Power Exchange (CSPE) energy and the shares available to each participant for each succeeding year through the life of the CPSE Agreement.

From July 1, 1983, through June 30, 1991, new preference customers as a group will be eligible for base allocations, adjusted by multiplying by a factor of 0.85 for conservation, from up to two-thirds of the firm energy which becomes available for allocation or reallocation due to contract expirations or an increase in the total resources available for allocation during the operating year in which they first receive service. However, a new preference customer's base allocation during the first year of service cannot exceed the ratio of all preference customer's allocations to their aggregate net firm energy, requirements.

BPA anticipates that there will be a transition in the allocation process until July 1, 1991. From that date forward, BPA will allocate energy on the basis of the relationship of each customer's total net firm energy requirements to all customers' total net firm energy requirements multiplied by the total amount of power BPA has available for allocation, less the 15 percent reserved for conservation rewards. The allocation can be increased for achievements in energy conservation, as provided under (4) *Conservation.*

BPA recognizes that an existing preference customer may elect to continue to purchase firm energy from BPA on the basis of its current contract until its expiration, and not to sign the new contract offered. If so, the customer will be entitled only to its allocation as determined under it current contract until expiration. Should the customer apply to continue purchasing firm energy from BPA prior to or at the time of contract expiration, it will be regarded as a preference applicant. As a perference applicant it will be accorded the same rights to available resources as other preference applicants. Following contract expiration, being a former BPA preference customer will not establish a special priority for BPA firm energy. The energy available from this customer's contract will be treated in an identical fashion to the energy available from an expired Federal agency or DSI contract.

The preference applicant's allocations will be held to serve them no more than 5 years following the date of application, if they are unable to accept service as anticipated. Subsequently, any such unused allocations will be made available to preference customers.

On July 1, 1982, BPA will allocate firm energy for the operating year commencing July 1, 1984. On July 1 of each operating year thereafter, BPA will notify its customers what their allocations of BPA firm energy will be 2 operating years hence.

(8) *Sharing of Benefits and Costs.* The allocation formula assures each preference customer and applicant a share of the available BPA firm energy to meet some portion or all of its system firm energy requirements. In addition, knowing what the base allocation will be, the total amount to be allocated, and how the allocation formula works gives customers and applicants a greater sense of certainty and some basis for planning conservation efforts and resources acquisitions.

Prior to July 1, 1991, allocations are not calculated on a pro rata basis. Therefore, the allocations do not reflect a full sharing of the economic benefits and costs of BPA firm energy among BPA customers. Another feature of the proposed policy assures that the sharing of benefits and costs will more closely approximate what would otherwise be the case after July 1, 1991, when all customers will receive pro rata allocations. This feature may cushion the change which would otherwise occur at that time by providing for a transition adjustment to the extent the new contracts permit:

(a) BPA will determine each customer's calculated pro rata share of the total BPA allocation (on the basis of (A/B)(C), adjusted for conservation, as appropriate).

(b) BPA will determine which customers will receive allocations that fall shy of their calculated pro rata shares and which customers would receive allocations that exceed their calculated pro rata shares.

(c) Those customers which require an increase in their allocations to meet their calculated pro rata shares may provide amounts of energy (offset energy) equal to their individual shortfalls to BPA at the average wholesale cost of their firm energy, which includes their allocations from BPA. In exchange, BPA would provide equivalent amounts of BPA firm energy to these customers.

(d) Those customers whose allocations exceed their calculated pro rata shares will receive firm energy in amounts equivalent to the allocations. The equivalent amounts would be comprised of an allocation of BPA firm energy equal to each customers's pro rata share of its allocation and the remainder which will be supplied from the offset energy received. These customers will pay for this offset energy at the average rate for all offset energy, and will pay for BPA energy, at BPA's rates.

(9) *Minimum Allocation. (8)* The minimum allocation provision, adjusted for conservation, will be included in the new contracts offered to existing preference customers and will be effective through June 30, 1991. It will not be available to new preference customers.

(10) *Grades of Power.* The BPA allocations policy applies to firm energy and system reserve energy only.

(11) *Rates.* BPA considers wholesale power rates a separate policy matter. However, future ratemaking would be affected if certain features of the proposal are eventually adopted.

Footnotes

1. Approximately 2900 average MW and 200 average MW of firm energy is currently committed by contract to DSI's and Federal agencies, respectively. New resource additions may become available as facilities not now in planning or construction are installed in existing Federal hydroelectric projects, or additional net-billed power is generated at plants presently under construction. The known new resource additions are reflected in the data on projected resources available for allocation.

2. This policy determination reflects the geographic preference contemplated by the Hungry Horse Dam Act of 1944 (43 U.S.C. 593a).

3. This should permit BPA to control the disposition of its resources, since it would discourage any preference customer from utilizing lower cost BPA energy in its system while selling its resources at profit, to the detriment of BPA and its other customers within the region.

4. Historically, BPA has sold power to the utilities without regard to the end uses served. BPA has complied with the mandatory provisions of the Bonneville Project Act to give preference and priority to public bodies and cooperatives. The Act also refers to the desirability of operating the generating facilities for the benefit of the general public, "* * * and particularly of domestic and rural consumers, * * *" but it does not restrict service to that type of load. BPA considers that Domestic and rural consumers have benefitted from its historical power marketing policies. The availability of low-cost Federal energy to serve multiple end uses has been one of a number of factors conducive to regional economic development.

5. The 15 percent targeted savings is partly based upon BPA's review of recent studies of potential conservation savings in the region, including the Skidmore, Owing and Merrill (SOM) Report July 1976 commissioned by BPA, and the 1977 conservation study prepared for the Northwest Energy Policy Project (NEPP) commissioned by the Northwest Governors. BPA has also considered the concepts in the "Alternative Scenario" proposed in January 1977 by the Natural Resources Defense Council (NRDC) for inclusion in BPA's Role EIS.

The findings of these studies vary:

(a) SOM foresees potential conservation savings of 33 percent by 1995 resulting from adoption of conservation programs ranging from moderate information and education efforts to strong mandatory measures and technologies not yet widely available;

(b) NEPP foresees potential conservation savings of 33 percent by 2000. However, it proceeds from a much lower consumption level, so all its curves fall below the SOM curves. NEPP's econometric model assumes higher energy prices and translates the effects of those prices into lower energy consumption.

The NRDC "Alternative Scenario" foresees potential conservation savings and changes in the region's industrial mix, postulating that only 4 of the 13 power generating facilities presently scheduled for completion between now and 1990 will actually prove to be needed by 1995. The "Alternative Scenario" does not specifically address needs after 1995.

BPA believes that the achievable energy savings through utility programs *may* be about one-half the maximum *potential* total savings identified in the NEPP and SOM studies. BPA is also looking at a target year of 1990, rather than 1995 or 2000. A regional and individual utility goal of 15 percent conservation savings by 1990 through existing and new programs is ambitious, but necessary and achievable. However, BPA recognizes that individual utility accomplishments may vary.

6. The allocations become effective July 1, 1983. Eighteen months should be sufficient for BPA to review the customers' and applicants' program proposals and for customers and applicants to develop and submit alternatives should BPA find the initial submission(s) deficient.

7. For policy analysis purposes, BPA has utlized data on loads and resources published in the 1979 PNUCC Blue Book of, for the East Group Utilities, data submitted to BPA in 1978.

8. The minimum allocation is not a statutory requirement. It was originally designed to meet *future* load requirements experienced by small preference customers unable to attract the necessary financing to develop their own energy resources and to assist the development of utilities to serve rural areas.

II. Public Meetings

A. *Public Information Forums.* BPA will conduct eight public information forums for its customers, consultants, and other interested groups and individuals. The forums will be educational in nature and will be designed (1) to explain the proposed allocation policy and supporting analyses and (2) to answer questions. Questions raised at the forums will be answered at that time, if possible, or in writing at a later date. The meetings will be held at the following locations and on the dates specified:

BPA Auditorium, 1002 NE. Holladay Street, Portland, Oregon, 9 a.m., October 31.

Mt. Hood Room, Travelodge at the Coliseum, 1441 NE. Second Avenue, Portland, Oregon, 7:30 p.m., November 5.

The Forum, Walla Walla Community College, 500 Tausick Way, Walla Walla, Washington, 7:30 p.m., November 5.

Forum R, Eugene Hotel, 222 East Broadway, Eugene, Oregon, 7:30 p.m., November 6.

City Council Chambers, 140 South Capitol, Idaho Falls, Idaho, 7:30 p.m. on November 6.

Terrace Room A, Ridpath Hotel, West 515 Sprague, Spokane, Washington, 7:30 p.m., November 7.

Phoenix C and D Rooms, Hyatt House-Seattle, Sea-Tac International Airport, 17001 Pacific Highway South, Seattle, Washington, 7:30 p.m. November 7.

Colt 44 and Colt 45 Rooms, Outlaw Inn, 1701 Highway 93 South, Kalispell, Montana, 7:30 p.m., November 8.

The meeting scheduled for 9 a.m. on Wednesday, October 31, in Portland will be more technical than the other meetings. The purpose of that meeting is to discuss the proposed allocation policy in greater detail.

B. *Procedure.* The meetings will be conducted by a chairperson who will be responsible for an orderly process. Each meeting will be recorded. The transcripts and questions and written answers will become part of the Official Record. The Record will be available for review and copying at BPA headquarters, 1002 Northeast Holladay Street, Portland, Oregon.

C. *Public Comment Forums.* Public Comment Forums to permit the public to submit oral comments regarding the proposed allocation policy will be scheduled in 1980 when the draft Environmental Impact Statement is available.

Written comments on the proposed allocation policy may be submitted to BPA at once. The written comments will become part of the Official Record and will be considered in the final allocation policy that will be developed by BPA. These comments should be submitted to the Public Involvement Coordinator, Bonneville Power Administration, P.O. Box 12999, Portland, Oregon 97212.

III. Glossary of Terms

An *allocation policy* is a plan to distribute the firm energy available for marketing from the FCRPS among BPA customers. The term "firm energy" includes energy from hydro, thermal, and other resources.

An *allocation formula* is a mathematical formula used to calculate the amount of firm energy which will be allocated to each qualified customer eligible for an allocation.

An *assured resource capability* means the capability of a customer's hydrogeneration resource based on adverse streamflows; the capability of a customer's thermal-generating resources based on probable or more conservative conditions; and the firm capability of other resources acquired by contract.

An *average megawatt (MW)* is a measure of average power over a given time period. To determine the average megawatts, divide the total megawatt hours measured in the time period by the number of hours in the period, e.g., if 10 megawatt hours of electric energy are measured over a 5-hour period, then 2 average megawatts would be the average rate at which power is delivered.

A *base allocation* is the fixed portion of a total allocation over a given time period. The remaining portion of an allocation, if any, may vary in amount depending on the availability of resources in excess of the aggregate base allocations.

The *Bonneville Project Act* is a statutory enactment (i.e., passed by Congress and signed into law by the President in 1937) to create the Bonneville Power Administration.

The *Bonneville Power Administration* (BPA or Bonneville) is an agency within the Federal Department of Energy. BPA was created to market the power produced by dams on the Columbia River.

Capacity refers to the amount of system power which can be supplied at any instant in time. It is usually measured over a 60-minute period. Capacity is expressed in terms of watts (kilowatts or megawatts for convenience). For example, if the maximum output from three resources is 100 megawatts each, the total capacity is 300 megawatts (300,000 kilowatts, or 300,000,000 watts).

Conservation means any reduction in energy consumption as a result of increases in the efficiency of energy use, production or distribution.

Critical period means that multimonth period, determined under the Pacific Northwest Coordination Agreement for adverse steamflows of historical record adjusted for changes in consumptive uses. The Coordinated System is comprised of the generating resources of the utilities who are parties to the Pacific Northwest Coordination Agreement. This agreement provides for the coordinated operation of the Columbia River and tributaries to maximize generation within other constraints. During the critical period the *least* amount of Estimated Firm Energy Load can be served from the Firm Resources of the parties to the Coordination Agreement. There are a number of consumptive uses which a dam with generating facilities may serve, e.g., municipal and industrial water supply or water for irrigation may be obtained from the water held in storage behind a dam.

Customer classes refer to the classes of customers BPA serves. They include preference customers, Federal agencies, direct-service industries, and investor-owned utilities.

Demand is a requirement for capacity. Demand results from electrical loads. Capacity refers to the ability of a system to produce sufficient power to meet customer loads (demands).

A *direct-service industrial customer (DSI)* is an industrial consumer who purchases energy directly from BPA. BPA presently has contracts with 17 DSI's.

DSI quartiles refer to the four blocks of energy sold to the DSI's. The first quartile (top) is energy which BPA may restrict for any reason or which DSI's may curtail for any reason. The second quartile (second from top) is energy which may be restricted by BPA to serve firm loads if and when delays occur in the construction of additional power plants, which, in turn, cause a shortage of firm energy to serve firm loads or when a forced outage occurs. The third and fourth quartiles (third and fourth from top) are firm power that BPA is committeed to serve without interruption except for 5 minutes of interruption to maintain system stability. Half the load operating at any given time may be restricted by BPA, if necessary, because of forced outages of generating equipment.

Electric power is the rate at which electric energy is being used to do work. Electric power is expressed in watts.

Electric energy is the amount of electricity which is consumed in doing a certain amount of work. Electric energy is equal to electric power (watts) multiplied by time (hours). Electric energy is expressed in kilowatthours or megawatthours.

End use refers to the kind of use to which the ultimate consumer puts the electric energy purchased. End uses are usually expressed in terms of the class of ultimate consumer of the electric energy: e.g., industry, commercial, residential or domestic, irrigation, or public authorities.

An *energy reserve* is a supply of electric energy which is held in reserve to meet a forced outage of a generator or a shortage. Reserves can be sold subject to restriction in order to continue meeting firm loads.

An *environmental assessment (EA)* is a documented analysis performed to determine if any significant environmental impacts may result from a proposed Federal action, and provide a basis for deciding whether an environmental impact statement is needed. An EA may be prepared to comply with the National Environmental Policy Act (NEPA, P.L. 91-190).

An *environmental impact statement (EIS)* is a documented analysis required by NEPA whenever a Federal agency proposes to take an action which would significantly affect the environment. An EIS must identify the proposed action and reasonable alternatives and provide comparative analysis of the environmental impacts of the proposed action and each alternative.

The *Federal Columbia River Power System (FCRPS)* refers to the Federal system of power dams and interconnecting transmission facilities located on the Columbia-Snake Rivers and tributaries in the Pacific Northwest and other resources acquired by BPA.

Firm energy means electric energy which is to be continuously available to the customer during a specified period to meet all or any agreed upon portion of the customer's electrical requirements, except capacity.

Firm power is a source of power which should be dependable under adverse conditions.

A *forced outage* is an interruption to service because of a reduced supply of electric power from a generating source or an inability to deliver power because of a transmission facility failure.

A *hydro resource* is a source of electricity which is derived from power produced by running water through turbines.

The *Hydro Thermal Power Program (HTPP)* was a program to obtain thermal generating resources in the Pacific Northwest region and integrate the thermal power with hydropower in order to supplement the Federal resources available for marketing.

An *interruptible load* is a load which can be temporarily interrupted when power is needed elsewhere in the system when a capacity or energy deficiency occurs. An interruptible load exists through contractual arrangements between a utility and its customer.

A *load* is the demand for electric power by a customer.

A *kilowatt* is a unit of power equal to 1,000 watts.

A *kilowatthour* is a unit of energy equal to 1 kilowatt for 1 hour.

A *megawatt* is a unit of power equal to 1,000,000 watts.

A *megawatthour* is a unit of energy equal to 1,000,000 watts for 1 hour.

A *minimum allocation* is a 25 MW fixed amount of firm energy which is reserved for specific preference customers. The minimum allocation is to meet future load growth experienced by small preference customers who might have difficulty financing or acquiring new energy resources.

Plant capacity factor is the ratio of energy actually produced at a generating plant to the energy that could have been produced under 100 percent operating conditions. E.g., a plant capacity factor of 0.50 (or 50%) means a plant actually produced half of the energy it ideally could have at full operation over the specific period of time.

A *power sales contract* is a contract instrument for the sale of BPA power to a customer.

Preference clause refers to that section of the Bonneville Project Act which granted statutory preference and priority for BPA's power to public bodies and cooperatives. The preference clause has been restated in a number of other statutes.

A *preference customer* is a customer who has a statutory right to preference and priority in the purchase of BPA firm energy and who is receiving power from BPA. Under law, preference customers must be public bodies or cooperatives.

Public bodies and cooperatives are BPA preference customers. The Bonneville Project Act of 1937 defines a "public body" or "public bodies" as states, public power districts, counties, and municipalities, including their component agencies or subdivisions. A "cooperative" or "cooperatives" means any form of non-profit-making organization(s) of citizens supplying, or created to supply, members with goods, commodities, or services, as nearly as possible at cost.

Requirements refer to the amount of electric power or energy associated with the electrical load.

Reserves means a portion of total generating capability planned to be available to serve loads in case of forced outages or unanticipated load growth.

Resources are the sources from which electric power and energy are produced. Resources include generating plants (nuclear, coal, hydro), purchase agreements, and conservation measures.

A *thermal resource* is a source of electricity which uses thermal energy (heat) to produce electricity. Usually thermal resources refer to natural gas, diesel, coal, nuclear power, oil, or bio-mass generating equipment.

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IV. Draft Tables and Exhibit

Table I

ESTIMATED NET FEDERAL RESOURCES AVAILABLE FOR ALLOCATION
AVERAGE FIRM ENERGY IN MEGAWATTS 1/
BY OPERATING YEAR 2/

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Resources															
1. Total Federal Hydro	7773	7765	7729	7731	7736	7722	7669	7664	7660	7656	7651	7647	7644	7643	7639
2. Federal Imports	358	358	358	206	20	-	-	-	-	-	-	-	-	-	-
3. Net-billed Thermal	1445	2004	2432	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490	2490
4. Total Resources	9576	10127	10519	10427	10246	10212	10159	10154	10150	10146	10141	10137	10134	10133	10129
Commitments															
5. Exports	97	99	101	103	105	108	111	108	108	108	108	108	108	108	108
6. Contracts Out	289	289	289	289	289	289	289	277	277	277	277	277	277	277	277
7. CSPE	488	462	437	412	387	363	344	327	315	302	289	276	264	252	238
8. Hydro Maintenance	32	33	33	34	34	34	34	34	34	34	34	51	51	51	51
9. USBR Reserve Power	63	69	77	80	80	83	88	91	92	92	93	95	96	96	96
10. Firm Losses	378	374	353	345	357	371	384	410	416	435	454	473	491	503	523
11. Montana Reservation	221	221	221	221	221	221	221	221	221	221	221	221	221	221	221
12. Sub-Total	1568	1547	1511	1484	1473	1469	1471	1468	1463	1469	1476	1501	1508	1508	1514
13. Industrial Contracts	2855	2622	2484	1595	370	83	83	6	1	-	-	-	-	-	-
14. Federal Agency Contracts	167	101	45	47	49	49	51	1	1	1	-	-	-	-	-
15. Total Federal Commitments	4590	4270	4040	3126	1892	1601	1605	1475	1465	1470	1476	1501	1508	1508	1514
16. System Energy Reserves to be Provided by:															
(a) DSI Contracts	957	880	834	536	125	28	28	2	----	----	----	----	----	----	----
(b) PC Contracts	8	85	131	429	840	937	937	963	965	965	965	965	965	965	965
17. Estimated Net BPA Resources Available For Allocation 3/	4978	5772	6348	6872	7514	7674	7617	7716	7720	7711	7700	7671	7661	7660	7650

Source of basic data is Pacific Northwest Utilities Conference Committee (PNUCC) Report on Long-Range Projection of Power Loads and Resources for Resource Planning, April 23, 1979

1/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, an operating year).
2/ July 1 - June 30
3/ Estimated net BPA resources available for allocation will be reduced by 15 percent to establish a conservation reserve.

Bonneville Power Administration
September 19, 1979

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EXPLANATION OF LINE ITEMS
FOR TABLE I

Line No.

1. Total Federal hydro resources include the hydro resource obligations of Federal and non-Federal projects to Canadian Storage Power Exchange (CSPE) and the Packwood Generation to reflect the Packwood project exchange agreements.

2. Reflects energy imports from the peak/energy exchange contracts with Pacific Southwest utilities and Montana Power Company.

3. Net-billed Thermal is public agencies' shares of Trojan and Washington Public Power Supply System's projects Nos. 1, 2, and 3, computed on the basis of 60 percent plant factor for first year of operation and 70 percent plant factor thereafter.

4. Sum of lines 1 through 3.

5. Exports include BPA's obligations to Montana Power Company for geographic preference, Hanford exchange agreement, wheeling payments, share of WNP #1 beginning July 1980, and Montana Power Company's share of restoration from the West Group Area as per Pacific Northwest Coordination Agreement.

6. Contracts out are the Federal obligations to the private utilities for headwater storage payments and WNP #1 allocations through June 30, 1996, deliveries to Clark and Snohomish County Public Utility Districts (PUD's) and other public agencies associated with Packwood exchange agreement.

7. CSPE obligation to individual private utilities and public agencies for contract purchases from the CSPE resources included under line 1.

8. Estimated hydro reduction due to maintenance required in the critical storage drawdown period.

9. Irrigation pumping requirements from power statutorily reserved for irrigation from United States Bureau of Reclamation (USBR) Federal projects authorized by Congress.

10. Estimated transmission line losses on the Federal System associated with serving firm loads.

11. Montana Reservation is the power reserved for sale within the State of Montana in accordance with the Hungry Horse Dam Act of June 4, 1944, as amended.

12. Sum of lines 5 through 11.

13. Industrial contracts are direct service contracts which will not be renewed upon expiration.

14. Net requirements of the Federal agencies until expiration of all contracts. Excludes 11 average megawatts of U.S. Bureau of Indian Affairs' own generation.

15. Sum of lines 12, 13, and 14.

16. System Energy Reserves to be provided by:

(a) DSI contracts - outstanding contracts with industry which provide for restriction of 2nd quartile.

(b) P.C. contracts - contracts with preference customers which will allow BPA to restrict energy deliveries.

17. Line 4 minus line 15 and line 16(b) combined.

Table II

BASIC LOAD-RESOURCE DATA

EXISTING PREFERENCE CUSTOMERS (PC), BPA, DSI AND FEDERAL AGENCIES
AVERAGE FIRM ENERGY IN MEGAWATTS 1/
BY OPERATING YEAR 2/

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998 3/
1. Net BPA Resources Available 4/ (Line 17, Table I)	4978	5772	6348	6872	7514	7674	7617	7716	7720	7711	7700	7671	7661	7660	7650
2. PC System Requirements	7495	7793	8108	8431	8759	9095	9445	9818	10206	10616	11033	11466	11921	12400	12895
3. 1975-76 PC Assured Resources	1146	1146	1146	1146	1146	1146	1146	1157	1157	1157	1157	1833	2006	2009	2012
4. PC Net System Req'mts. Line 2 minus Line 3	6349	6647	6962	7285	7613	7949	8299	8661	9049	9459	9876	9633	9915	10391	10883
5. BPA Base Allocation to PC	5792	5843	5890	5937	5981	6022	6059	6091	6122	6149	6174	1553	---	---	---
6. PC Additional Req'mts. Line 4 minus Line 5	557	804	1072	1348	1632	1927	2240	2570	2927	3310	3702	8080	9915	10391	10883
7. Remaining BPA Resources 4/ Line 1 minus Line 5	(814)	(71)	458	935	1533	1652	1558	1625	1598	1562	1526	6118	7661	7660	7650
8. Unassigned PC Resources															
Centralia	257	257	257	257	257	257	257	257	257	257	257	257	257	257	257
WNP 4	---	62	760	875	875	875	875	875	875	875	875	875	875	875	875
WNP 5	---	---	56	679	781	781	781	781	781	781	781	781	781	781	781
Boardman	37	37	37	37	37	37	37	37	37	37	37	37	37	37	37
a. SUBTOTAL LARGE THERMAL	294	356	1110	1848	1950	1950	1950	1950	1950	1950	1950	1950	1950	1950	1950
b. Small Thermal	35	35	34	34	34	34	34	34	34	34	34	8	---	---	---
c. Other Hydro	504	526	543	555	579	597	605	611	623	631	638	162	---	---	---
d. TOTAL UNASSIGNED RES.	833	917	1687	2437	2563	2581	2589	2595	2607	2615	2622	2120	1950	1950	1950
9. DSI Expired Contracts															
a. 3 Quartile Load	---	231	349	1117	2144	2432	2432	2432	2432	2432	2432	2432	2432	2432	2432
b. 2 Quartile Load	---	155	233	709	1324	1516	1516	1516	1516	1516	1516	1516	1516	1516	1516
c. 35 MW Peak Limit	---	41	63	196	369	448	448	448	448	448	448	448	448	448	448
10. Federal Agency (FA) Loads															
a. Total Net Requirements	184	187	190	193	196	198	201	204	207	209	212	216	219	222	226
b. Net Requirements - FA's with Expired Contracts 5/	17	86	145	146	147	149	150	203	206	208	212	216	219	222	226
c. Net Req'mts. - FA's under 10b in PC Service Areas 5/	---	53	108	108	108	110	110	146	148	151	155	158	162	165	169
d. 35 MW Peak Limit	---	30	61	61	61	63	63	83	83	83	84	84	84	84	84
11. a. Assumed New PC Net Requirements	500	525	549	575	600	635	665	700	730	765	800	840	880	925	970
b. Assumed New PC Net Requirements	1500	1570	1650	1725	1800	1900	2000	2100	2200	2300	2410	2520	2640	2770	2910
c. Assumed New PC Net Requirements	3000	3150	3300	3450	3600	3800	4000	4190	4390	4600	4820	5050	5290	5540	5810

Source of basic data is Pacific Northwest Utilities Conference Committee (PNUCC) Report on Long-Range Projection of Power Loads and Resources for Resource Planning, April 23, 1979

1/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, an operating year).
2/ July 1 - June 30
3/ Projections are available through 1998 only.
4/ Amounts shown will be reduced by 15 percent to establish a conservation reserve.
5/ Cumulative totals

Bonneville Power Administration
September 19, 1979

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Explanation of Line Items
For Table II

Line No.

1. - BPA Resources less Commitments to Direct-Service Industries (DSI's), Federal agencies, as well as State of Montana's power reservation.

2. - Total load for existing preference customers from 1979 PNUCC Blue Book less Chelan County PUD's Colockum load.

3. - Preference customer assured resources in 1975-76 as used in determining hydro allocations under existing contracts.

4. - Line 2 minus line 3.

5. - BPA allocations to existing preference customers. These allocations are based on the assumption that all existing PC's will sign new contracts containing allocation provisions identical to those in their current contracts but which are valid through September 20, 1994 in all cases (under the status quo, the last of the current contracts with existing PC's expires September 20, 1994).

6. - Line 4 minus line 5.

7. - Resources which become available to BPA as existing DSI and Federal agency contracts expire, less BPA commitments.

8. - Additional hydro resources available to preference customers not included in line 3. The sum of line 3 plus line 8d equals 1979 Blue Book resources of preference customers.

9. - Loads of DSI's located within or adjacent to preference customers' service areas and whose BPA contracts have expired.

(a) and (b). The amount of industrial firm energy load based on 2 or 3 quartiles.

(c) The amount of industrial load eligible for allocation limited to the energy related to 35 MW peak.

10. - Federal agencies loads reflecting Flathead Indian irrigation district load (U.S. Bureau of Indian Affairs).

(a) Total net requirements of Federal agencies served by BPA.

(b) Net requirements of Federal agencies whose contracts have expired.

(c) Net requirements of Federal agencies located within or adjacent to preference customer service areas and whose contracts with BPA have expired.

(d) Federal agencies' loads limited to 35 megawatts of peak located within or adjacent to preference customer service area.

11. - Estimated levels of new preference customer net firm energy requirements.

Table III

BPA PREFERENCE CUSTOMER'S ESTIMATED FIRM ENERGY
REQUIREMENTS FOR JULY-JUNE OPERATING YEARS
1983-84 THROUGH 1997-98 1/
AVERAGE MEGAWATTS

Sheet 1 of 4

LARGER CUSTOMERS	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Large Municipals															
Eugene, Oregon	301.3	311.0	320.3	328.9	338.0	347.1	356.6	365.8	373.9	382.5	391.3	400.0	408.3	416.1	423.8
Idaho Falls, Idaho	69.5	73.2	77.2	81.3	85.7	90.3	95.1	100.2	105.5	111.0	116.8	122.8	129.1	135.6	142.4
McMinnville, Oregon	41.8	43.1	44.5	45.9	47.3	48.8	50.4	52.0	53.6	55.3	57.2	59.0	60.9	62.9	64.9
Port Angeles, Washington	106.8	108.3	109.4	111.3	113.0	114.8	116.7	118.7	120.7	122.8	125.0	127.3	129.7	132.2	134.8
Richland, Washington	92.0	93.3	94.5	95.0	95.4	95.9	96.4	97.0	97.4	98.0	98.5	99.1	99.6	100.1	100.7
Seattle, Washington	1110.8	1136.7	1162.3	1185.2	1211.9	1233.5	1238.5	1251.8	1272.5	1290.9	1307.2	1321.2	1334.3	1347.1	1357.4
Springfield, Oregon	119.7	123.6	127.6	131.9	136.4	141.1	146.0	151.1	156.3	161.8	167.5	173.4	179.5	185.9	192.5
Tacoma, Washington	660.2	681.0	702.2	723.4	745.1	766.9	788.9	811.2	834.1	857.2	880.9	905.3	930.0	955.4	981.2
Total Large Municipals	2502.1	2570.2	2638.0	2702.9	2772.8	2838.4	2888.6	2947.8	3014.0	3079.5	3144.4	3208.1	3271.4	3335.3	3397.7
Large PUD's															
Benton Co. PUD #1	227.3	241.5	257.2	274.7	293.7	314.1	336.5	358.3	378.5	400.7	424.8	451.2	480.0	511.4	545.6
Central Lincoln PUD	170.8	177.4	182.5	187.7	193.2	198.8	204.6	210.6	216.9	223.3	229.9	236.8	244.0	251.3	258.8
Chelan Co. PUD #1	156.1	162.4	168.1	174.2	180.0	186.5	193.5	200.4	207.2	214.3	221.9	229.1	236.3	243.8	251.4
Clallam Co. PUD #1	67.0	70.9	75.0	79.4	84.0	88.9	94.1	99.6	105.3	111.3	117.5	124.0	130.7	137.9	145.2
Clark Co. PUD #1	430.6	448.3	466.0	484.4	502.7	521.3	540.0	558.9	577.9	595.3	616.2	635.5	655.7	676.2	696.1
Clatskanie PUD	109.0	118.1	128.1	138.9	144.9	145.5	160.2	177.4	187.3	204.5	208.7	213.0	217.3	221.6	222.6
Cowlitz Co. PUD #1	616.6	632.9	653.0	665.4	677.9	690.4	703.9	716.2	729.4	743.5	756.7	770.3	784.0	797.6	810.1
Douglas Co. PUD #1	77.5	81.0	84.6	88.8	93.2	97.7	102.5	107.8	113.7	119.8	126.1	133.1	140.5	148.3	157.0
Franklin Co. PUD #1	102.3	106.7	112.1	117.7	122.9	128.5	134.5	140.9	147.7	154.9	162.5	170.6	179.1	188.2	197.8
Grant Co. PUD #2	231.3	240.9	251.0	263.0	275.3	288.6	303.0	318.1	334.1	350.7	368.3	386.7	406.0	426.3	447.7
Grays Harbor Co. PUD #1	213.4	221.4	229.8	238.5	247.6	257.0	266.7	276.8	287.3	298.2	309.5	321.2	333.4	346.0	359.0
Klickitat Co. PUD #1	33.6	35.6	37.7	40.0	42.3	44.8	47.6	50.5	53.8	56.9	60.3	63.9	67.7	71.5	75.8
Lewis Co. PUD #1	114.5	120.3	126.4	132.8	139.6	146.8	154.3	162.2	170.6	179.3	188.4	197.8	207.6	217.9	228.6
Mason Co. PUD #3	61.1	65.0	69.1	73.5	78.2	83.3	88.6	94.3	100.4	106.6	113.3	120.2	127.5	135.1	143.2
Northern Wasco PUD	29.1	30.1	31.0	31.9	32.8	33.9	34.9	36.0	37.2	38.3	39.5	40.7	42.1	43.4	44.7
Okanogan Co. PUD #1	73.9	77.7	81.9	86.3	90.8	95.6	100.7	106.1	111.6	117.6	123.7	130.0	136.7	143.7	151.0
Pacific Co. PUD #2	43.7	46.0	48.4	50.9	53.6	56.4	59.3	62.4	65.6	69.0	72.4	76.1	79.9	83.9	87.8
Snohomish Co. PUD #1	653.4	667.0	680.2	692.8	705.4	717.6	729.2	740.2	750.8	760.8	770.2	779.0	787.2	795.4	802.4
Tillamook Co. PUD #1	46.6	47.7	48.7	49.7	50.9	52.0	53.1	54.3	55.4	56.6	57.9	59.1	60.4	61.7	63.0
Total Large PUD's	3457.8	3590.9	3730.8	3870.6	4009.0	4147.7	4307.2	4471.0	4630.7	4801.6	4967.8	5138.3	5316.1	5501.2	5688.0
Large Coop's															
Benton REA	55.1	59.4	64.2	69.5	75.2	81.5	88.4	96.0	104.1	112.9	122.4	132.5	143.6	155.4	168.0
Big Bend Electric Coop.	86.9	96.8	107.7	120.1	134.0	149.9	167.5	187.3	209.4	234.1	261.5	292.1	326.1	363.8	405.7
Central Electric Coop.	39.5	42.3	45.3	48.5	52.0	55.7	59.6	63.9	68.4	73.1	78.1	83.3	88.9	94.7	100.8
Consumers Power, Inc.	61.1	65.7	70.8	76.2	81.9	88.3	95.1	102.6	110.5	119.0	128.0	137.7	147.9	158.9	170.5
Coos-Curry Electric Coop.	38.2	40.0	41.9	44.0	46.1	48.3	50.6	53.1	55.7	58.4	61.3	64.4	67.6	71.0	74.6
Inland Power & Light Co.	91.8	100.9	110.7	121.5	133.6	147.2	162.1	178.5	196.9	216.8	238.7	262.5	288.6	317.2	348.4
Lane Co. Electric Coop.	36.1	37.4	33.6	39.9	41.3	42.7	44.1	45.6	47.3	48.9	50.5	52.3	54.1	56.0	57.9
Peninsula Light Co., Inc.	43.1	46.8	50.9	55.1	59.2	63.4	67.4	71.2	75.1	79.0	82.9	86.9	91.2	95.6	100.2
Raft River Electric Coop.	33.1	34.5	35.8	37.2	38.7	40.2	41.7	43.3	45.0	46.8	48.6	50.5	52.4	54.4	56.5
Salem Electric	38.1	39.9	41.8	43.8	45.9	48.1	50.4	52.8	55.3	57.9	60.6	63.5	66.4	69.5	72.6
Umatilla Electric Coop.	121.2	124.7	131.5	141.8	145.4	149.4	153.7	158.0	162.5	167.1	171.9	176.9	182.0	187.2	192.6
Total Large Coop's	644.2	688.4	739.2	797.6	853.3	914.7	980.6	1052.3	1130.2	1214.0	1304.5	1402.6	1508.8	1623.7	1747.8
Total Large Customers	6604.1	6849.5	7108.0	7371.1	7635.1	7900.8	8176.4	8471.1	8774.9	9095.1	9416.7	9749.0	10096.3	10460.2	10833.5

Table III

BPA PREFERENCE CUSTOMER'S ESTIMATED FIRM ENERGY
REQUIREMENTS FOR JULY-JUNE OPERATING YEARS
1983-84 THROUGH 1997-98
AVERAGE MEGAWATTS

Sheet 2 of 4

SMALLER CUSTOMERS	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Small Municipals															
Albion, Idaho	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
Bandon, Oregon	8.1	8.4	8.8	9.0	9.3	9.6	9.9	10.2	10.5	10.9	11.3	11.6	12.0	12.4	12.7
Blaine, Washington	5.4	5.6	5.8	6.1	6.3	6.5	6.8	7.1	7.4	7.6	8.0	8.3	8.6	8.9	9.3
Bonners Ferry, Idaho	7.9	8.2	8.4	8.8	9.1	9.4	9.7	10.1	10.5	10.8	11.2	11.6	12.0	12.5	12.9
Burley, Idaho	16.8	18.4	20.2	22.1	24.3	26.6	29.2	32.0	35.0	38.4	41.9	45.8	50.0	54.5	59.3
Canby, Oregon	16.2	17.6	19.1	20.7	22.5	24.4	26.5	28.7	31.1	33.7	36.4	39.4	42.5	45.9	49.5
Cascade Locks, Oregon	5.1	5.2	5.2	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.2	6.3	6.5	6.6	6.8
Centralia, Washington	27.4	28.6	29.8	31.1	32.4	33.8	35.3	36.9	38.4	40.1	41.8	43.6	45.4	47.3	49.3
Cheney, Washington	14.9	15.3	15.8	16.2	16.7	17.1	17.6	18.1	18.6	19.1	19.7	20.2	20.8	21.4	22.0
Consolidated ID No. 19, Wash.	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Coulee Dam, Washington	4.5	4.6	4.8	5.0	5.2	5.3	5.5	5.7	5.9	6.1	6.3	6.5	6.7	7.0	7.2
Declo, Idaho	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7	.7
Drain, Oregon	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.6	4.7	4.8	4.9	5.1	5.2
Eatonville, Washington	1.7	1.7	1.8	1.9	1.9	2.0	2.1	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.7
Ellensburg, Washington	24.8	25.6	26.4	27.2	28.1	29.0	29.9	30.8	31.8	32.8	33.8	34.9	36.0	37.2	38.3
Fircrest, Washington	6.5	6.6	6.8	7.0	7.2	7.4	7.6	7.8	8.1	8.3	8.5	8.7	9.0	9.3	9.6
Forest Grove, Oregon	26.2	27.8	29.6	31.5	33.5	35.6	37.8	40.2	42.6	45.2	47.9	50.7	53.7	56.8	60.0
Heyburn, Idaho	12.7	13.3	13.9	14.6	15.3	16.1	16.9	17.7	18.5	19.4	20.3	21.3	22.3	23.3	24.4
McCleary, Washington	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9
Milton, Washington	3.5	3.6	3.7	3.9	4.0	4.2	4.4	4.6	4.7	4.9	5.1	5.3	5.5	5.7	6.0
Milton-Freewater, Oregon	19.5	20.7	22.0	23.4	24.9	26.5	28.2	30.1	32.0	34.1	36.2	38.5	40.9	43.3	46.0
Minidoka, Idaho	.1	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Monmouth, Oregon	8.0	8.2	8.4	8.7	8.9	9.2	9.5	9.8	10.1	10.4	10.7	11.0	11.4	11.7	12.0
Rupert, Idaho	10.8	11.7	12.7	13.8	15.0	16.4	18.0	19.7	21.7	23.9	26.3	29.0	31.9	35.3	38.8
Steilacoom, Washington	5.8	6.1	6.4	6.8	7.1	7.5	7.9	8.3	8.7	9.2	9.6	10.1	10.6	11.1	11.6
Sumas, Washington	1.2	1.2	1.3	1.4	1.4	1.5	1.6	1.7	1.7	1.8	1.9	1.9	2.0	2.1	2.2
Vera IRA District, Washington	23.0	24.3	25.9	27.9	30.3	33.3	37.1	39.8	42.9	46.4	50.3	54.8	59.7	65.3	71.6
Total Small Municipals	259.9	272.8	287.1	303.0	319.6	337.9	358.3	378.5	399.8	423.0	447.6	474.0	502.3	532.8	564.9
Small PUD's															
Ferry Co. PUD #1	8.7	9.2	9.6	10.1	10.6	11.2	11.8	12.4	13.0	13.7	14.4	15.1	15.9	16.6	17.5
Kittitas Co. PUD #1	6.5	6.9	7.3	7.5	7.8	8.2	8.6	8.9	9.4	9.8	10.2	10.7	11.1	11.6	12.1
Mason Co. PUD #1	9.1	9.6	10.2	10.8	11.4	12.1	12.8	13.6	14.4	15.2	16.1	17.0	17.9	18.9	19.9
Pend Oreille Co. PUD #1	21.0	22.0	23.1	24.3	25.5	26.8	28.1	29.5	31.0	32.5	34.1	35.8	37.6	39.5	41.5
Skamania Co. PUD #1	18.4	19.2	20.1	21.1	22.2	23.2	24.3	25.5	26.7	28.0	29.3	30.7	32.1	33.6	35.2
Wahkiakum Co. PUD #1	7.3	7.6	8.0	8.3	8.7	9.0	9.4	9.8	10.2	10.6	11.1	11.5	12.0	12.5	13.0
Whatcom Co. PUD #1	14.5	14.5	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Total Small PUD's	85.5	89.0	92.9	96.7	100.8	105.1	109.6	114.3	119.3	124.4	129.8	135.4	141.2	147.3	153.8

Table III

EPA PREFERENCE CUSTOMER'S ESTIMATED FIRM ENERGY
REQUIREMENTS FOR JULY-JUNE OPERATING YEARS
1983-84 THROUGH 1997-98
AVERAGE MEGAWATTS

Sheet 3 of 4

SMALLER CUSTOMERS	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Small Coop's (Excl. Montana)															
Alder Mutual	.3	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4	.4
Blachly Lane Elec. Coop.	18.7	19.6	20.5	21.4	22.3	23.3	24.4	25.5	26.8	27.9	29.2	30.6	32.0	33.4	34.9
Clearwater Power Co.	26.8	28.3	29.9	31.5	33.2	35.0	36.8	38.8	40.9	43.1	45.3	47.7	50.2	52.8	55.5
Columbia Basin Elec. Coop.	21.5	22.5	23.6	24.8	26.0	27.3	28.6	30.0	31.6	33.1	34.7	36.4	38.1	40.0	41.9
Columbia Power Coop.	3.8	4.0	4.2	4.4	4.5	4.7	4.9	5.1	5.3	5.5	5.7	6.0	6.2	6.4	6.7
Columbia REA	31.5	33.7	35.7	37.8	40.0	42.3	44.8	47.4	50.2	53.2	56.2	59.4	62.7	66.2	69.9
Douglas Elec. Coop.	23.1	24.6	26.1	27.8	29.6	31.5	33.7	35.9	38.3	41.0	43.7	46.6	49.7	53.1	56.6
East End Mutual	1.9	2.0	2.2	2.4	2.6	2.8	3.0	3.3	3.5	3.8	4.1	4.4	4.8	5.1	5.5
Elmhurst Mutual	25.4	27.2	29.1	31.2	33.5	35.9	38.4	41.2	44.1	47.2	50.4	53.8	57.4	61.2	65.1
Fall River Elec. Coop.	29.9	32.5	35.3	38.5	41.9	45.6	49.7	54.1	58.8	64.0	69.6	75.5	81.9	88.7	96.1
Farmers Elec. Co.	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.1	2.2	2.3	2.5	2.7	2.9	3.0	3.2
Harney Elec. Coop.	20.6	21.6	22.7	23.7	24.9	26.1	27.3	28.6	30.0	31.4	32.9	34.4	36.0	37.6	39.3
Hood River Elec. Coop.	12.7	13.3	13.8	14.4	15.0	15.6	16.2	16.9	17.6	18.3	19.1	19.8	20.6	21.5	22.3
Idaho Co. L.& P. Coop.	7.1	7.5	7.9	8.4	8.9	9.6	10.3	11.0	11.8	12.7	13.6	14.6	15.6	16.7	17.9
Kootenai Elec. Coop., Inc.	26.5	28.4	30.4	32.6	34.9	37.4	40.1	42.9	46.0	49.2	52.6	56.2	60.0	64.0	68.2
Lakeview L.& P. Co.	27.5	28.5	29.6	30.7	31.9	33.1	34.3	35.6	37.0	38.4	39.8	41.3	42.9	44.5	46.1
Lincoln Elec. Coop. (Wash.)	24.2	26.0	27.7	29.6	31.7	33.8	36.2	38.7	41.4	44.2	47.2	50.3	53.7	57.1	60.8
Lost River Elec. Coop.	9.3	9.7	10.2	10.8	11.3	12.0	12.6	13.3	14.0	14.7	15.5	16.3	17.2	18.0	18.9
Lower Valley P. & L. Co.	51.8	57.1	62.9	69.3	76.4	84.2	92.8	102.3	112.5	123.7	135.8	149.1	163.4	178.9	195.7
Midstate Elec. Coop.	23.4	24.9	26.4	28.1	29.9	31.8	33.8	35.9	38.2	40.6	43.0	45.6	48.3	51.1	54.1
Nespelem Valley Elec. Coop.	6.3	6.7	7.1	7.5	7.9	8.4	8.9	9.5	10.2	10.7	11.5	12.2	12.9	13.7	14.6
Northern Lights, Inc. 2/	21.7	22.9	24.3	25.9	27.5	29.3	31.1	33.3	35.5	37.7	40.3	42.9	45.5	48.6	51.7
Ohop Mutual	4.5	4.8	5.1	5.4	5.7	6.1	6.4	6.8	7.2	7.6	8.1	8.5	9.0	9.5	10.0
Okanogan Co. Elec. Coop.	4.2	4.5	4.8	5.0	5.3	5.6	5.9	6.2	6.6	6.9	7.3	7.7	8.1	8.5	9.0
Orcas P. & L. Co.	18.8	20.1	21.4	22.9	24.4	26.0	27.7	29.5	31.3	33.3	35.3	37.4	39.6	41.9	44.4
Parkland L. & W. Co.	12.8	13.1	13.5	13.9	14.3	14.7	15.1	15.5	16.0	16.4	16.9	17.4	17.9	18.4	18.9
Prairie Power Coop.	2.6	2.8	3.0	3.3	3.6	3.9	4.2	4.5	4.9	5.3	5.7	6.2	6.7	7.2	7.7
Riverside Elec. Co.	1.4	1.5	1.6	1.8	1.9	2.1	2.2	2.3	2.5	2.7	2.9	3.1	3.3	3.5	3.7
Rural Elec. Co.	10.0	10.5	11.1	11.6	12.1	12.6	13.1	13.6	14.3	14.9	15.5	16.2	16.8	17.6	18.4
Salmon River Elec. Coop.	6.1	6.5	6.8	7.2	7.7	8.1	8.6	9.1	9.7	10.2	10.8	11.4	12.1	12.7	13.4
South Side Elec. Lines	3.9	4.1	4.3	4.4	4.6	4.7	4.9	5.0	5.2	5.4	5.6	5.8	6.0	6.2	6.4
Surprise Valley Elec. Corp.	16.4	17.5	18.6	19.8	21.1	22.5	23.9	25.5	27.2	29.0	30.8	32.7	34.8	37.0	39.2
Tanner Electric	4.1	4.5	4.9	5.4	6.0	6.6	7.2	8.0	8.7	9.6	10.6	11.6	12.7	14.0	15.3
Unity L. & P. Co.	7.6	8.1	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.7	15.6	16.6	17.7	18.8
Wasco Elec. Coop.	13.5	14.3	15.0	15.7	16.4	17.2	18.1	18.9	19.9	20.9	21.9	23.0	24.1	25.3	26.6
Wells Rural Elec. Co.	13.6	15.2	17.0	19.1	21.4	24.1	26.9	30.2	33.7	37.7	42.0	46.9	52.2	58.1	64.6
West Oregon Elec. Coop.	11.1	11.6	12.3	12.9	13.5	14.1	14.7	15.4	16.1	16.9	17.6	18.4	19.3	20.2	21.2
Total Small Coop's(Excl.Mont.)	545.9	581.9	619.6	660.5	703.9	750.8	800.4	854.4	912.5	973.7	1038.8	1108.1	1181.6	1259.8	1343.0
Total Small Pref. Customers (Excl. Montana)	891.3	943.7	999.6	1060.2	1124.3	1193.8	1268.3	1347.2	1431.6	1521.1	1616.2	1717.5	1825.1	1939.9	2061.7

Table III

BPA PREFERENCE CUSTOMER'S ESTIMATED FIRM ENERGY
REQUIREMENTS FOR JULY-JUNE OPERATING YEARS
1983-84 THROUGH 1997-98
AVERAGE MEGAWATTS

Sheet 4 of 4

SMALLER CUSTOMERS	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Small Coop's (Montana Only)															
Flathead Elec. Coop.	18.5	19.8	21.1	22.6	24.1	25.8	27.5	29.4	31.4	33.5	35.7	38.0	40.4	42.9	45.6
Glacier Elec. Coop.	20.6	21.1	21.6	22.1	22.6	23.2	23.7	24.2	24.8	25.4	26.0	26.6	27.2	27.8	26.5
Lincoln Elec. Coop. (Montana)	7.8	8.1	8.3	8.6	8.9	9.1	9.4	9.6	9.9	10.2	10.5	10.8	11.1	11.4	11.8
Missoula Elec. Coop.	18.5	19.8	21.3	22.9	24.6	26.4	28.4	30.6	32.8	35.4	37.8	40.7	43.6	46.8	50.0
Northern Lights, Inc. 3/	12.9	13.3	13.6	13.8	14.1	14.4	14.8	15.0	15.4	15.8	16.1	16.5	17.0	17.4	17.9
Ravalli Elec. Coop.	13.3	14.0	14.9	15.7	16.7	17.6	18.7	19.7	20.8	22.1	23.2	24.5	25.9	27.3	28.7
Vigilante Elec. Coop.	12.9	13.9	15.1	16.3	17.6	18.8	20.0	21.3	22.8	24.4	26.1	27.8	29.5	31.5	33.6
Total Small Coop's(Montana)	104.5	110.0	115.9	122.0	128.6	135.3	142.5	149.8	157.9	166.8	175.4	184.9	194.7	205.1	216.1
Total Small Coop's	650.4	691.9	735.5	782.5	832.5	886.1	942.9	1004.2	1070.4	1140.5	1214.2	1293.0	1376.3	1464.9	1559.1
Total Small Pref. Customers	995.8	1053.7	1115.5	1182.2	1252.9	1329.1	1410.8	1497.0	1589.5	1687.9	1791.6	1902.4	2019.8	2145.0	2277.8
Total Large Pref. Customers 4/	6604.1	6849.5	7108.0	7371.1	7635.1	7900.8	8176.4	8471.1	8774.9	9095.1	9416.7	9749.0	10096.3	10460.2	10833.5
Total Small Pref. Customers 5/															
Excl. Montana Coop's	891.3	943.7	999.6	1060.2	1124.3	1193.8	1268.3	1347.2	1431.6	1521.1	1616.2	1717.5	1825.1	1939.9	2061.7
Montana Coop's Only	104.5	110.0	115.9	122.0	128.6	135.3	142.5	149.8	157.9	166.8	175.4	184.9	194.7	205.1	216.1
Total Small Pref. Cust.	995.8	1053.7	1115.5	1182.2	1252.9	1329.1	1410.8	1497.0	1589.5	1687.9	1791.6	1902.4	2019.8	2145.0	2277.8
Total Preference Customers															
Excl. Montana Coop's	7495.4	7793.2	8107.6	8431.3	8759.4	9094.6	9444.7	9818.3	10206.5	10616.2	11032.9	11466.5	11921.4	12400.1	12895.2
Incl. Montana Coop's	7599.9	7903.2	8223.5	8553.3	8888.0	9229.9	9587.2	9968.1	10364.4	10783.0	11208.3	11651.4	12116.1	12605.2	13111.3

1/ From PNUCC April 23, 1979, "Long-Range Projection of Loads & Resources" 1979-80 Through 1998-99.

2/ Loads excluding the State of Montana.

3/ Loads in State of Montana only.

4/ Loads exceed the minimum allocation.

5/ Loads are less than the minimum allocation.

Table IV

Existing BPA Preference Customers 1/
Estimated System Loads, Calculated BPA Allocations, BPA Obligations, and Utility Deficits
By Year of Contract Expiration
(Average Megawatts) 2/

Col 1 Contract Expiration Year	Col 2 Contract Expir. Date	Col 3 Sys Load Fall '78 Estimate	Col 4 Net Resources 1975-76	Col 5 Net Sys Req'mts Fall '78 Estimate	Col 6 3/ Hydro Alloc	Col 7 Thermal Alloc	Col 8 CSPE Purch Incl BPA Guarantee	Col 9 4/ Calc BPA Alloc Incl CSPE (Columns 6+7+8)	Col 10 BPA Obligation Incl CSPE Guarantee Total Obl	Col 11 Prorated Obl	Col 12 Deficit (Col 9-Col 5)
1983-84											
Farmers Elec. Coop.	08/07/83	1.3		1.3	25.0	0.2		25.2	1.3	0.1	—
East End Mutual	08/21/83	1.9		1.9	25.0	0.5		25.5	1.9	0.3	—
Lost River Elec. Coop.	08/21/83	9.3		9.3	25.0	0.5		25.5	9.3	1.6	—
Burley, Idaho	08/30/83	16.8		16.8	25.0	3.8		28.8	16.8	2.8	—
Riverside Elec. Co.	08/30/83	1.4		1.4	25.0	0.2		25.2	1.4	0.2	—
Salmon River Electric Coop.	08/30/83	6.1		6.1	25.0	0.8		25.8	6.1	1.0	—
Albion, Idaho	08/31/83	0.5		0.5	25.0	0.2		25.2	0.5	0.1	—
Declo, Idaho	08/31/83	0.7		0.7	25.0	0.3		25.3	0.7	0.1	—
Heyburn, Idaho	08/31/83	12.7		12.7	25.0	3.9		28.9	12.7	2.1	—
Minidoka, Idaho	08/31/83	0.1		0.1	25.0	—		25.0	0.1	—	—
Surprise Valley Elec. Corp.	09/30/83	16.4		16.4	25.0	3.6		28.6	16.4	4.1	—
1984-85											
Clatskanie PUD	09/01/84	118.1		118.1	62.5	31.8	1.0	95.3	95.3	15.9	-22.8
Bandon, Oregon	12/31/84	8.4		8.4	25.0	1.5		26.5	8.4	4.2	—
Eatonville, Washington		1.7		1.7	15.0*	0.4		15.4	1.7	0.9	—
Ellensburg, Washington		25.6		25.6	25.0	6.4		31.4	25.6	12.8	—
Eugene, Oregon		311.0	46.3	264.7	184.1	51.5	26.8	262.4	262.4	131.2	-2.3
Fircrest, Washington		6.6		6.6	15.5*	1.1		16.6	6.6	3.3	—
Forest Grove, Oregon		27.8		27.8	25.0	7.7	1.5	34.2	27.8	13.9	—
Milton, Washington		3.6		3.6	15.2*	0.8		16.0	3.6	1.8	—
Monmouth, Oregon		8.2		8.2	25.0	1.0		26.0	8.2	4.1	—
Port Angeles, Washington		108.3		108.3	60.9	28.6	2.4	91.9	91.9	46.0	-16.4
Steilacoom, Washington		6.1		6.1	25.0	1.5		26.5	6.1	3.1	—
Central Lincoln PUD		177.4		177.4	118.0	41.6	4.9	164.5	164.5	82.3	-12.9
Mason Co. PUD #1		9.6		9.6	25.0	1.8		26.8	9.6	4.8	—
Pend Oreille Co. PUD #1		22.0	13.4	8.6	25.0	5.3	1.0	31.3	8.6	4.3	—
Wahkiakum Co. PUD #1		7.6		7.6	25.0	1.6		26.6	7.6	3.8	—
Alder Mutual		0.4		0.4	25.0	0.1		25.1	0.4	0.2	—
Central Elec. Coop.		42.3		42.3	25.0	11.6		36.6	36.6	18.3	-5.7
Elmhurst Mutual		27.2		27.2	25.0	8.0		33.0	27.2	13.6	—
Flathead Elec. Coop.		19.8		19.8	25.0	3.9	0.5	29.4	19.8	9.9	—
Glacier Elec. Coop.		21.1		21.1	25.0	6.6		31.6	21.1	10.6	—
Lakeview L & P Co.		28.5		28.5	18.8*	5.5		24.3	24.3	12.2	-4.2
Lincoln Elec. Coop. (Mont.)		8.1		8.1	25.0	1.7	0.5	27.2	8.1	4.1	—
Missoula Elec. Coop.		19.8		19.8	25.0	7.0	0.5	32.5	19.8	9.9	—
Northern Lights, Inc.		36.2		36.2	25.0	15.1	1.7	41.8	36.2	18.1	—
Ohop Mutual		4.8		4.8	25.0	0.8		25.8	4.8	2.4	—
Parkland L & W		13.1		13.1	25.0	1.3		26.3	13.1	6.6	—
Peninsula Light Co.		46.8		46.8	25.0	12.1		37.1	37.1	18.6	-9.7
Ravalli Elec. Coop		14.0		14.0	25.0	4.9	0.5	30.4	14.0	7.0	—
West Oregon Elec. Coop.	12/31/84	11.6		11.6	25.0	2.4		27.4	11.6	5.8	—
Raft River Elec. Coop.	06/15/85	34.5		34.5	25.0	1.5		26.5	26.5	26.5	-8.0
1985-86											
McCleary, Washington	11/30/85	4.7		4.7	25.0	0.6		25.6	4.7	2.0	—
Clallam Co. PUD #1	12/31/85	75.0		75.0	40.6	19.0		59.6	59.6	29.8	-15.4
Whatcom Co. PUD #1	12/31/85	14.6		14.6	25.0	0.8		25.8	14.6	7.3	—
Cowlitz Co. PUD #1	01/31/86	653.0	9.1	643.9	308.7	224.6	12.2	545.5	545.5	318.2	-98.4
Tillamook PUD	02/23/86	48.7		48.7	37.3	7.0	2.4	46.7	46.7	31.1	-2.0
Douglas Elec. Coop.	03/21/86	26.1		26.1	25.0	6.2		31.2	26.1	19.6	—
Consolidated ID No. 19	04/20/86	0.2		0.2	25.0	—		25.0	0.2	0.2	—
Nespelem Valley Elec. Coop.	05/04/86	7.1		7.1	25.0	0.5	0.2	25.7	7.1	5.9	—
Okanogan Co. PUD #1	05/20/86	81.9		81.9	44.4	21.6		66.0	66.0	60.5	-15.9
Milton-Freewater, Oregon	06/30/86	22.0		22.0	25.0	4.5		29.5	22.0	22.0	—
1986-87											
Blaine, Washington	07/21/86	6.1		6.1	25.0	1.2		26.2	6.1	0.5	—
Tanner Electric	09/26/86	5.4		5.4	25.0	1.5		26.5	5.4	1.4	—
Salem Electric	10/04/86	43.8		43.8	25.0	11.5	2.0	38.5	38.5	9.6	-5.3
Springfield, Oregon	12/06/86	131.9		131.9	72.9	33.8	2.4	109.1	109.1	45.5	-22.8
Harney Elec. Coop.	12/21/86	23.7		23.7	25.0	3.0		28.0	23.7	11.9	—
Lewis Co. PUD #1	03/06/87	132.8	0.1	132.7	62.8	38.6		101.4	101.4	67.6	-31.3
Hood River Elec. Coop.	03/31/87	14.4		14.4	25.0	3.1		28.1	14.4	10.8	—
Centralia, Washington	04/22/87	31.1	10.1	21.0	25.0	6.3		31.3	21.0	17.5	—
Rupert, Idaho	05/05/87	13.8		13.8	25.0	3.1		28.1	13.8	11.5	—
Benton REA	06/01/87	69.5		69.5	25.0	3.9		28.9	28.9	26.5	-40.6
Blachly-Lane Elec. Coop.	06/07/87	21.4		21.4	25.0	5.4		30.4	21.4	19.6	—

1/ There are only 115 preference customers shown. Washington Public Power Supply System (WPPSS) is not included. WPPSS is a preference customer eligible to receive firm energy while constructing thermal power plants.

2/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, an operating year).

3/ Some former utility customers of Tacoma City Light receive hydro allocations of less than 25 average MW through contractual agreements, to which BPA, Tacoma, and the affected utilities are parties.

4/ Amounts shown will be reduced by 15 percent to reflect establishment of a conservation reserve.

DRAFT

Bonneville Power Administration
September 13, 1979

Table IV

Existing BPA Preference Customers 1/
Estimated System Loads, Calculated BPA Allocations, BPA Obligations, and Utility Deficits
By Year of Contract Expiration
(Average Megawatts) 2/

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6 3/	Col 7	Col 8	Col 9 4/	Col 10	Col 11	Col 12
Contract Expiration Year	Contract Expir. Date	Sys Load Fall '78 Estimate	Net Resources 1975-76	Net Sys Req'mts Fall '78 Estimate	Hydro Alloc	Thermal Alloc	CSPE Purch Incl BPA Guarantee	Calc BPA Alloc Incl CSPE (Columns 6+7+8)	BPA Obligation Incl CSPE Guarantee: Total Obl	BPA Obligation Incl CSPE Guarantee: Prorated Obl	Deficit (Col 9-Col 5)
1987-88											
Inland P & L Co.	07/26/87	133.6		133.6	40.6	32.5	2.4	75.5	75.5	6.3	-58.1
Coulee Dam, Washington	08/30/87	5.2		5.2	25.0	1.3	0.5	26.8	5.2	0.9	—
Vigilante Elec. Coop.	09/08/87	17.6		17.6	25.0	3.8		28.8	17.6	2.9	—
Columbia REA	10/09/87	40.0		40.0	25.0	10.7		35.7	35.7	8.9	-4.3
Vera Irrig. Dist.	10/27/87	30.3		30.3	25.0	6.1	1.0	32.1	30.3	10.1	—
Prairie Power Coop.	11/07/87	3.6		3.6	25.0	1.4		26.4	3.6	1.2	—
Kittitas Co. PUD #1	11/29/87	7.8	0.9	6.9	25.0	1.7		26.7	6.9	2.9	—
Unity L & P Co.	01/08/88	9.9		9.9	25.0	2.2		27.2	9.9	5.0	—
Skamania Co. PUD #1	03/21/88	22.2		22.2	25.0	3.7	1.0	29.7	22.2	16.6	—
Clearwater Power Co.	03/21/88	33.2		33.2	25.0	5.0		30.0	30.0	22.5	-3.2
Drain, Oregon	05/23/88	4.2		4.2	25.0	0.7		25.7	4.2	3.9	—
Kootenai Elec. Coop.	06/03/88	34.9		34.9	25.0	8.1		33.1	33.1	30.3	-1.8
1988-89											
Big Bend Elec. Coop	07/09/88	149.9		149.9	35.5	6.4		41.9	41.9	—	-108.0
Orcas P & L Co.	07/31/88	26.0		26.0	25.0	6.2		31.2	26.0	2.2	—
Idaho Co. L & P Co.	08/27/88	9.6		9.6	25.0	0.7	0.5	26.2	9.6	1.6	—
Grant Co. PUD #2	08/31/88	288.6	31.5	257.1	93.0	52.5	2.2	147.7	147.7	24.6	-109.4
Fall River Elec. Coop.	08/31/88	45.6		45.6	25.0	7.2		32.2	32.2	5.4	-13.4
McMinnville, Oregon	10/18/88	48.8		48.8	29.8	9.0	2.0	40.8	40.8	13.6	-8.0
Lane Co. Elec. Coop.	11/16/88	42.7		42.7	31.9	2.6	2.0	36.5	36.5	15.2	-6.2
Lower Valley P & L Co.	12/13/88	84.2	0.9	83.3	25.0	12.1		37.1	37.1	15.5	-46.2
Sumas, Washington	12/17/88	1.5		1.5	25.0	0.3		25.3	1.5	0.8	—
1989-90											
Columbia Basin Elec. Coop.	07/08/89	28.6		28.6	25.0	5.7		30.7	28.6	—	—
Wasco Elec. Coop.	01/29/90	18.1		18.1	25.0	3.1		28.1	18.1	10.6	—
Rural Elec. Coop.	04/10/90	13.1		13.1	25.0	2.5		27.5	13.1	9.8	—
1990-91											
Columbia Power Coop.	07/24/90	5.1		5.1	25.0			25.0	5.1	0.4	—
Clark Co. PUD #1	12/31/90	558.9		558.9	252.7	134.3	14.6	401.6	401.6	200.8	-157.3
Canby, Oregon	03/02/91	28.7		28.7	25.0	6.0		31.0	28.7	19.1	—
Ferry Co. PUD #1	03/21/91	12.4		12.4	25.0	0.4		25.4	12.4	9.3	—
Benton Co. PUD #1	04/01/91	358.3		358.3	108.1	87.9	3.9	199.9	199.9	149.9	-158.4
Consumers Power, Inc.	04/13/91	102.6		102.6	29.3	20.1		49.4	49.4	37.0	-53.2
Cheney, Washington	04/29/91	18.1		18.1	25.0	3.3		28.3	18.1	15.1	—
Umatilla Elec. Coop.	05/06/91	158.0		158.0	57.4	50.1		107.5	107.5	89.6	-50.5
Northern Wasco PUD	06/11/91	36.0		36.0	25.0	6.4		31.4	31.4	28.8	-4.6
Okanogan Co. Elec. Coop.	06/11/91	6.2		6.2	25.0	1.3		26.3	6.2	5.7	—
Franklin Co. PUD # 1	06/25/91	140.9		140.9	51.3	27.4	3.9	82.6	82.6	82.6	-58.3
1991-92											
Midstate Elec. Coop.	10/08/91	38.2		38.2	25.0	8.0		33.0	33.0	8.3	-5.2
Pacific Co. PUD #2	11/05/91	65.6		65.6	27.2	12.0		39.2	39.2	13.1	-26.4
1992-93											
Wells Rural Elec. Co.	07/27/92	37.7		37.7	25.0	0.4		25.4	25.4	2.1	-12.3
Snohomish Co. PUD #1	08/10/92	760.8	0.5	760.3	445.5	162.7	7.3	615.5	615.5	51.3	-144.8
Cascade Locks, Oregon	10/20/92	6.0		6.0	25.0	0		25.0	6.0	2.0	—
Mason Co. PUD #3	12/01/92	106.6	0.1	106.5	36.9	17.1		54.0	54.0	22.5	-52.5
Klickitat Co. PUD #1	03/09/93	56.9		56.9	25.0	7.3		32.3	32.3	21.5	-24.6
Idaho Falls, Idaho	03/31/93	111.0	2.4	108.6	36.7	12.1		48.8	48.8	36.6	-59.8
Greys Harbor Co. PUD #1	03/31/93	298.2		298.2	124.0	54.9	7.3	186.2	186.2	139.6	-112.0
1993-94											
Southside Elec. Lines	07/23/93	5.6		5.6	25.0	0.9		25.9	5.6	0.5	—
Bonners Ferry, Idaho	09/30/93	11.2	1.8	9.4	25.0	1.8	0.2	27.0	9.4	2.4	—
Tacoma, Washington	11/01/93	880.9	258.6	622.3	191.7	157.7	61.0	410.4	410.4	136.8	-211.9
Seattle, Washington	11/04/93	1307.2	709.1	598.1	149.4	174.0	61.0	384.4	384.4	128.1	-213.7
Lincoln Elec. Coop. (Wash.)	12/31/93	47.2		47.2	25.0	4.0	0.5	29.5	29.5	14.8	-17.7
Richland, Washington	01/30/94	98.5		98.5	49.8	22.8	3.9	76.5	76.5	44.6	-22.0
1994-95											
Coos-Curry Elec. Coop.	07/26/94	64.4		64.4	28.7	6.6	2.4	37.7	37.7	3.1	-26.7
Douglas Co. PUD #1	08/31/94	133.1	0.7	132.4	56.0	14.7	1.0	71.7	71.7	12.0	-60.7
Chelan Co. PUD #1	09/20/94	229.1	60.0	169.1	38.1	26.9	4.9	69.9	69.9	17.5	-99.2

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2/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, an operating year).

3/ Some former utility customers of Tacoma City Light receive hydro allocations of less than 25 average MW through contractual agreements, to which BPA, Tacoma, and the affected utilities are parties.

4/ Amounts shown will be reduced by 15 percent to reflect establishment of a conservation reserve.

Notes for Table IV
by column heading

Existing BPA Preference Customers

Column 1 Preference customers whose firm power sales contracts expire during the operating year (July 1 - June 30) shown. Some customers have more than one firm power sales contract with BPA. For analytical purposes, BPA assumed that all their contracts would expire on the termination date of the longest running contract.

Column 2 The contract expiration date is the termination date of the longest running power sales contract for each customer.

Column 3 Estimated total system loads of each customer shown for the operating year in which the longest running power sales contract terminates. These load estimates are contained in the PNUCC Report, Long-Range Projection of Power Loads and Resources for Resource Planning, dated April 23, 1979 (Blue Book).

Column 4 Contract year 1975-76 assured resources defined in Section 22 of the General Contract Provisions attached to the Power Sales Contracts of preference customers. These resources are used to determine the hydro allocation under existing agreements.

Column 5 Net customer requirements. (Column 3 minus Column 4).

Columns 6, 7, 8 Hydro allocation, thermal allocation, and Canadian Storage Power Exchange (CSPE) purchases defined in Section 22 of the General Contract Provisions attached to the Power Sales Contracts of preference customers.

Column 9 Sum of Columns 6, 7, and 8. This would be the total Hydro-Thermal-CSPE average megawatt allocation from BPA to each utility under current contracts for the entire contract year within which the contract expires.

Column 10 BPA's estimated obligation to each customer during the contract year in which the power sales contract expires but limited to forecasted requirements.

Note: The obligation shown in Column 10 is less than the calculated contract allocation (Column 9) if the hydro plus thermal plus CSPE allocations exceed the estimated net requirements in Column 5 (Column 3 or Column 9, whichever is smaller).

Column 11 Column 10 prorated by whole months for the contract year within which the power sales contract expires. This is BPA's estimated obligation during the partial year in which the contract expires limited to forecasted requirements.

Column 12 Net preference customer energy deficit based on contract year 1975-76 assured resources after utilizing total BPA allocation. (Column 9 minus Column 5).

Federal Agency Customers of BPA
Within or Adjacent to BPA Preference Customers' Service Territory

Contract Federal Agency Customer	Preference Customer	Average MW[1] Calendar Year (CY) 1978 [2]	Percent of BPA Total Federal Agency Customer Load	Expiration Date
Air Force, Fairchild	Inland Power & Light	2.8	3.2	6/85
Bureau of Reclamation, Roza	Benton REA	3.3	3.7	8/88
DOE-Richland-300 Area	Richland, Washington	10.3	11.7	12/84
-FFTF[3] & Midway 230	Benton PUD	30.6	34.7	12/84
Navy-Jim Creek	Snohomish Co. PUD	1.2	1.3	6/93
Bureau of Indian Affairs-Wapato	Benton REA	1.4	1.6	7/85
-Flathead	Missoula Electric Coop.	10.9	12.3	6/90
TOTAL		60.5	68.5	

Not Within or Adjacent to BPA Preference Customer Service Territory

Contract Federal Agency Customer	Local Utility	Average MW[1] Calendar Year (CY) 1978	Percent of BPA Total Federal Agency Customer Load	Expiration Date
Bureau of Mines, Albany	Pacific Power & Light	.8	.9	12/85
Navy-Bangor	Puget Sound Power & Light	12.1	13.7	1/84
-Bremerton	Puget Sound Power & Light	14.9	16.9	7/90
TOTAL		27.8	31.5	
BPA TOTAL FEDERAL AGENCY SERVICE		88.3	100.0	

1/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, a calendar year).

2/ Data available by calendar year only

3/ Reflects partial development of Fast Flux Test Facility (FFTF) Full load development is not expected until 1982.

Bonneville Power Administration
September 21, 1979

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Direct Service Industrial (DSI) Customers of BPA
Within or Adjacent to BPA Preference Customers' Service Territory

DSI Customer 1/	Preference Customer	Average MW 2/ Calendar Year (CY) 1978 3/	Percent of BPA Total DSI Load	Contract Expiration Date
Alcoa-Vancouver	Clark Co. PUD #1	228.1	7.2	6/87
Alcoa-Wenatchee	Chelan Co. PUD #1	215.7	6.8	6/87
Anaconda-Columbia Falls	Flathead Electric Coop.	329.7	10.4	9/87
Intalco-Ferndale	Whatcom Co. PUD #1	421.8	13.3	10/84
Kaiser-Spokane	Inland Power & Light	434.9	13.7	10/86
Kaiser-Tacoma	Tacoma, Washington	149.9	4.7	10/86
Kaiser-Trentwood	Inland Power & Light	53.4	1.7	10/86
Martin-Marietta-The Dalles	Northern Wasco PUD	166.5	5.3	2/88
Martin-Marietta-Goldendale	Klickitat Co. PUD #1	205.7	6.5	2/88
Reynolds-Longview	Cowlitz Co. PUD #1	406.5	12.8	12/86
Carborundum-Vancouver	Clark Co. PUD #1	26.6	.8	12/85
Georgia Pacific-Bellingham	Whatcom Co. PUD #1	7.2	.2	7/84
Oremet-Albany	Consumers Power, Inc.	4.3	.2	5/88
Stauffer-Silver Bow	Vigilante Electric Coop.	50.2	1.6	4/88
TOTAL		2700.5	85.2	

Not Within or Adjacent to BPA Preference Customer Service Territory

DSI Customer	Local Utility	Average MW 2/ Calendar Year (CY) 1978	Percent of BPA Total DSI Load	Contract Expiration Date
Crown Zellerbach-Port Townsend	Puget Sound Power & Light	8.4	.3	8/83
Hanna Nickel-Riddle	Pacific Power & Light	88.2	2.8	6/90
Pacific Carbide	Portland General Elec.	7.2	.2	9/91
Pennwalt	Portland General Elec.	41.1	1.3	12/85
Reynolds-Troutdale	Portland General Elec.	264.0	8.3	12/86
Union Carbide	Portland General Elec.	15.5	.5	5/81
Alcoa-Addy	Washington Water Power	45.9	1.4	6/87
TOTAL		470.3	14.8	
BPA TOTAL DSI SERVICE		3170.8	100.0	

1/ Alumax excluded. BPA contractually committed to provide power. Plant yet to be constructed. If constructed, it would presumably be in Umatilla Electric Cooperative Service territory.

2/ Average megawatts are determined by dividing megawatthours by the number of hours in a specific period (in this case, a calendar year).

3/ Data available by calendar year only.

Bonneville Power Administration
September 21, 1979

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COMPARISON OF PROPOSED AND ALTERNATIVE ALLOCATION POLICIES

ALLOCATION ISSUES	CONTINUATION OF EXISTING POLICIES AND PRACTICES	PROPOSED AND ALTERNATIVE ALLOCATION POLICIES					
		Alternative #1	Alternative #2	Alternative #3 (Proposal)	Alternative #4	Alternative #5	Alternative #6
1. Customers Served							
A. Presently served preference customers	Entitled to preference and priority	same[1/]	same	same	same	same	same
B. New qualified preference applicants	No power available until contracts expire and/or new resources become available	Not served	500 MW load assumed	3,000 MW load assumed	Not served	1,500 MW load assumed	1,500 MW load assumed
C. Presently served Federal Agencies	BPA will serve total load	Served by local utility; energy associated with 35 MW peak load served by preference customers eligible for allocation	Total load served by BPA	Served by local utility; the entire load served by preference customers eligible for allocation	Served by local utility; energy associated with 35 MW peak load served by preference customers eligible for allocation	same	same
D. Direct-service industries (DSIs, industries served directly by BPA)	BPA will continue to serve to extent energy available beyond needs of preference customers	Served by local utility; total DSI load served by preference customers eligible for allocation but subject to withdrawal	Served by local utility; total DSI load served by preference customers eligible for allocation	Served by local utility; base 2 quartiles of DSI load served by preference customers eligible for allocation	Served by local utility; energy associated with 35 MW peak load served by preference customers eligible for allocation	Served by local utility; total DSI load served by preference customers eligible fcr allocation	Served by local utility; total DSI load served by preference customers eligible for allocation but subject to withdrawal
2. Customer-Owned Resources	Resources are used as scheduled in the PNUCC "Blue Book" April 23, 1979	1975-76 assured resources as used in present contract for hydro allocation	X[2/]	See footnote 3	All assured resources committed to serve load before BPA allocation	All hydro resources constructed prior to 75-76 must be committed to serve load before BPA allocation	X
3. End-Use Loads Served	No distinction made	same	same	No new or expanding single load which equals or exceeds 10 average MW in any year or in a 3-year period is eligible for allocation	Priority for rural and domestic; withdrawable from all other loads	same	same
4. Amount of Firm Energy Available for Sale							
A. Hydro Plants	Based on critical water flow	same	same	same	same	same	same
B. Thermal Plants	60 percent plant factor first year of operation; 75 percent thereafter	60 percent plant factor first year of operation; 70 percent thereafter	X	X	X	X	X
C. Reserves	Maintain a capacity reserve as part of the firm energy sale equal to 25 percent of DSI total load.	System reserves sold as separate class of power to preference customers	X	X	X	X	X
5. Durations and Terms of Allocation	All existing contracts run to expiration; contracts with presently served customers would be renewed.	As contracts expire, new agreements written so that all contracts expire on 9/20/94	X	New 20-year contracts offered; all contracts will terminate on July 1, 2001; provide 2 years advance notice of of each preference customer's allocation on July 1 (e.g., on July 1, 1983, for OY 1985)	New 20-year contracts offered effective July 1, 1983, or when executed; all contracts will expire June 30, 2003	X	X
6. Minimum Allocation	25 average MW minimum continued to presently served preference customers' whose contracts are extended	25 average MW thru September 20, 1994, none thereafter for presently served preference customers only	X	25 average MW thru June 30, 1991, none thereafter for presently served preference customers only	25 average MW thru September 20, 1994, none thereafter for presently served preference customers only	No minimum allocation	X
7. Grades of Power	Firm energy allocated	Firm energy and system reserves allocated	X	X	X	X	X
8. Load Determination and Resource Availability	Preference customers estimates reviewed and approved by BPA	same	same	same	same	same	same
9. Rates	Separate Policy Matter	same	same	same	same	same	same
10. Conservation	Separate Policy Matter	Customer must immediately design a conservation program to achieve a 15 percent savings of what its energy requirements would otherwise have been absent a program in OY 1989-90 or sooner, or an effective conservation program which can be implemented by the utility. If the program is not satisfactory, customer is not eligible for additional allocation. If savings of more than 15 percent, allocation may be increased by 1 percent for each 1 percent over 15 percent in the operating year in which excess savings are realized.	X	X	X	X	X

1/-A "same" indicates no departure from the "Continuation of Existing Policies and Practices" Alternative.
2/-An "X" indicates no departure from the previous alternative.
3/-As of July 1, 1983, all generating resources owned or purchased (including those withdrawn or withdrawable) which are equal to or less costly than BPA firm energy are to be used in customer's own system. Such resources will affect the customer's base allocation, if any. All other resources will be made available at cost first to BPA, second to BPA's preference customers, and third to other regional entities. If their resources are disposed of in a different manner, the amount of the BPA allocation will be reduced by the amount of the resource sold.

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Bonneville Power Administration
September 21, 1979

BILLING CODE 6450-01-C

Exhibit

Section 22—General Contract Provisions Attached to Existing Power Sales Contracts

"(i) the larger of (A) 25,000 average kilowatts of energy (219 million kilowatt-hours), or (B) the amount, for the Contract Year commencing July 1, 1975 (Contract Year 1976), of the Purchaser's system firm energy load, less the assured energy capability of the Purchaser's resources, excluding from such assured energy capability the energy supplied by the Administrator to the Purchaser's system under the Hanford Exchange Agreement and the Canadian Entitlement Exchange Agreement; *provided however*, that if the Purchaser has available to it a hydroelectric resource which operated to supply a portion of its system loads in the Contract year commencing July 1, 1974, the Purchaser's allocation for each Contract Year commencing on or after July 1, 1983, shall be reduced by the amount, if any, by which the assured energy capability, as determined by the Administrator, for such resource in such Contract Year exceeds the assured energy capability, as determined by the Administrator, for such resource in Contract Year 1976;

"(ii) an amount of Firm Energy determined by multiplying 1881.8 average megawatts, the amount of Firm Energy determined to be available to the Administrator for each Contract Year from the Trojan Project and from Washington Public Power Supply System's Nuclear Projects Nos. 1, 2 and 3 ("Thermal Plants"), by a fractión whose numerator is the difference between the Purchaser's system firm energy load for the Contract Year prior to the effective date of the notice of insufficiency, and for the Contract Year 1976, and whose denominator is the sum of the differences in system firm energy loads for such Contract Years for all of the Administrator's Northwest preference customers having power sales contracts with the Administrator which contain a provision similar to this provision; *provided however*, that the determination of the Purchaser's system firm energy load for the Contract Year prior to the effective date of the notice of insufficiency used in the above computation shall not exceed 103 percent of the Purchaser's estimated system firm energy load for such Contract Year specified in the Purchaser's estimate furnished the Administrator as of December 31, 1973; *provided further*, that for applicable contract years the 1881.8 average megawatts specified above shall be either increased by the amount the Administrator determines is available to the Administrator through addition Net Billing Agreements from other thermal projects, including Centralia and Boardman (Pebble Springs), or decreased by the amount the Administrator determines is withdrawn from Trojan; and

"(iii) an amount of Firm Energy determined by subtracting the Purchaser's Canadian Entitlement energy, prior to any exchange made pursuant to section 5(c) of the Canadian Entitlement Exchange Agreement, for such Contract Year beginning one year after the notice of insufficiency becomes effective, from the Purchaser's entitlement for Canadian Entitlement energy, prior to any exchange pursuant to section 5(c) of the Canadian Entitlement Exchange Agreement, in the Contract Year which begins the date the notice of insufficiency becomes effective.

"The Purchaser's allocation, determined pursuant to subsection (a)(1), shall not be affected by the Purchaser's acquisition or reconstruction of electric power resources after June 30, 1976.

"(2) In addition to the amounts allocated to preference customers, including the Purchaser, pursuant to subparagraph (1)(i) above, the Administrator shall determine prior to July 1, 1978, the amount, if any, of firm energy load carrying capability available on the Federal System in the Contract Year 1976, which is available for allocation but which is not allocated to such customers pursuant to such paragraph (1)(i). The Purchaser's allocation for any Contract Year may be additionally increased by the Administrator, effective on written notice served not less than 90 days prior to such Contract Year, to reflect increases in Firm Energy that he determines can be made available hereunder. At least 90 days prior to either such allocation the Administrator shall make available to the Purchaser, for timely comment, the criteria he intends to use to make such allocation.

BPA believes that this proposed policy, if implemented, would serve the public interest and efficiently utilize and promote widespread use in the Pacific Northwest of Federal firm energy.

Dated: September 27, 1979.

Sterling Munro,

Administrator.

[FR Doc. 79-30804 Filed 10-4-79; 8:45 am]

BILLING CODE 6450-01-M

federal register

Friday
October 5, 1979

Part VII

Department of the Interior

Office of Surface Mining Reclamation and Enforcement

Determination of Completeness for Permanent Program Submission From the State of Montana

DEPARTMENT OF THE INTERIOR

Office of Surface Mining Reclamation and Enforcement

Determination of Completeness for Permanent Program Submission From the State of Montana

AGENCY: Office of Surface Mining Reclamation and Enforcement (OSM) U.S. Department of the Interior.

ACTION: Notice of Determination of Completeness of Submission.

SUMMARY: On August 3, 1979, the state of Montana submitted to OSM its proposed permanent regulatory program under the Surface Mining Control and Reclamation Act of 1977 (SMCRA). This notice announces the Regional Director's determination as to whether the Montana program submission contains each required element specified in the permanent regulatory program regulations. The Regional Director has concluded his review and has determined the Montana program submission is complete.

ADDRESSES: Written comments on the Montana program and a summary of the public meeting are available for public review, 8:00 a.m.–4:00 p.m., Monday through Friday, excluding holidays at: Office of Surface Mining Reclamation and Enforcement, Region V, Post Office Building, Room 225, 1823 Stout Street, Denver, Colorado 80202.

Copies of the full text of the proposed Montana program are available for review during regular business hours at the OSM Regional Office above and at the following offices of the State regulatory authority:

Montana Department of State Lands, 1625 11th Avenue, Capitol Station, Helena, Montana 59601.

Department of State Lands Field Office, 1245 North 29th Street, Billings, Montana 59101.

FOR FURTHER INFORMATION CONTACT: Sylvia Sullivan, Public Information Officer, Office of Surface Mining Reclamation and Enforcement, Post Office Building, Room 270, 1823 Stout Street, Denver, Colorado 80202.

SUPPLEMENTARY INFORMATION: On August 6, 1979, OSM received a proposed permanent regulatory program from the State of Montana. Pursuant to the provisions of 30 CFR Part 732, "Procedures and Criteria for Approval or Disapproval of State Program Submissions" (44 FR 15326–15328, March 13, 1979), the Regional Director, Region V, published notification of receipt of the program submission in the **Federal Register** of August 13, 1979 (44 FR 47414–47415) and in the following newspapers of general circulation within Montana:

Billings Gazette, Bozeman Chronicle, Montana Standard, Great Falls Tribune, Hamilton Republic, Havre News, Helena Independent Record, Kalispell Inter Lake, Livingston Enterprise, Miles City Star, and Missoulian.

The August 13, 1979, notice set forth information concerning public participation pursuant to 30 CFR 732.11. This information included a summary of the program submission, announcement of a public review meeting on September 12, 1979, in Helena, Montana to discuss the submission and its completeness, and announcement of a public comment period until September 12, 1979, for members of the public to submit written comments relating to the program and its completeness. Further information may be found in the permanent regulatory program regulations and **Federal Register** notice referenced above.

This notice is published pursuant to 30 CFR 732.11(b) and constitutes the Regional Director's decision on the completeness of the Montana program. Having considered public comments, testimony presented at the public review meeting and all other relevant information, the Regional Director has determined that the Montana submission does fulfill the content requirements for program submission under 30 CFR 731.14 and is therefore complete.

No later than November 20, 1979, the Regional Director will publish a notice in the **Federal Register** and in the following newspapers of general circulation in Montana initiating substantive review of the program submission:

Billings Gazette, Bozeman Chronicle, Montana Standard, Great Falls Tribune, Hamilton Republic, Havre News, Helena Independent Record, Kalispell Inter Lake, Livingston Enterprise, Miles City Star, and Missoulian.

The review will include an informal public hearing and written comment period. Procedures will be detailed in that notice. Further information concerning how that substantive review will be conducted may be found in 30 CFR 732.12.

The Office of Surface Mining is not preparing an environmental impact statement with respect to the Montana regulatory program, in accordance with Section 702(d) of SMCRA (30 U.S.C. § 1292(d)), which states that approval of State programs shall not constitue a major action within the meaning of Section 102(2)(C) of the National Environmental Policy Act.

Dated: October 1, 1979.

Donald A. Crane,

Regional Director.

[FR Doc. 79-31034 Filed 10-4-79; 8:45 am]

BILLING CODE 4310-05-M

federal register

Friday
October 5, 1979

Part VIII

Office of Management and Budget

Uniform Administrative Requirements for Grants-in-Aid to State and Local Governments; Circular A-102

OFFICE OF MANAGEMENT AND BUDGET

Circular A-102, "Uniform Administrative Requirements for Grants-in-Aid to State and Local Governments"

This notice revises OMB Circular A-102, "Uniform administrative requirements for grants-in-aid to State and local governments." The revision was based on a recommendation by the President's Cash Management Task Force, and brings the grant payment policies of the Circular into line with the cash management policies of the Department of the Treasury.

The Treasury regulations provide that Federal cash made available to recipients of grants shall be timed to coincide with their cash needs. However, in many cases Federal payments to recipients have included amounts that are withheld by the recipient from contractors to assure satisfactory completion of the contract. The time lapse from the point the recipient received payment and the contractor was paid in full has varied from thirty days to more than a year. This practice resulted in interest costs to the Federal Government that could have been avoided.

The revision requires that recipients shall not be reimbursed for amounts that are to be withheld to assure satisfactory completion of the work. The change is effective January 1, 1980. However, Federal grantor agencies may defer implementation to January 1, 1981, for recipients that must amend their laws in order to comply.

The proposed revision was published for comment in the **Federal Register** on October 18, 1978. In response to the publication, we received about 50 comments from Members of Congress, Federal agencies, State and local governments, associations, and others. There follows a summary of the major comments grouped by subject and our response to each.

Comment. Several commentators pointed out that the proposed revision would deprive them of the interest earned on the Federal payments.

Response. The present practice encourages the premature disbursement of Federal funds and results in increased interest costs to the Federal Government. It is estimaed that this amounts to about $12 million a year. The revision would end this, while continuing the policy of assuring that funds are available to grant recipients when needed by them to make payments.

Comment. Many commentators stated that the revision would require extensive changes in their accounting systems because, as originally drafted, the revision appeared to apply to all costs, and would have required conversion to cash basis accounting.

Response. We agreed with these comments and have modified the revision. As presented here, the revision will permit recipients to continue to bill on the accrued cost basis, handling retained amounts as adjustments in the billing system.

Comment. Some commentators stated that the proposed revision would require a change in State or local law.

Response. We agreed that time should be provided to permit any necessary changes in State or local law. As presented here, the revision authorizes agencies to defer implementation until January 1, 1981, to permit such changes.

The following is added to paragraph 5, Attachment J, *Grant Payment Requirements:* "With respect to payments to contractors, recipients shall not be reimbursed for amounts that are to be withheld to assure satisfactory completion of the work. These amounts will be paid when recipients make final payment including amounts withheld."

Further Information: For further information contact Mr. John J. Lordan, Chief, Financial Management Branch, Office of Management and Budget, New Executive Office Building, 726 Jackson Place, N.W., Washington, D.C. 20503, (202) 395-6823.

James T. McIntyre, Jr.,
Director.

[FR Doc. 79-31004 Filed 10-4-79; 8:45 am]
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